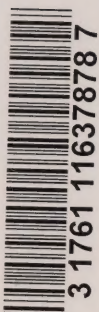


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National Energy Board



Reasons for Decision

Amoco Canada Petroleum Company Ltd.

Canadian Occidental Petroleum Ltd.

**North Canadian Marketing Inc. and
East Georgia Cogeneration (Vermont)
Limited Partnership**

ProGas Limited

Shell Canada Limited

GH-3-91

March 1992

**Volume II
Gas Exports**





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National Energy Board

Reasons for Decision

IN THE MATTER OF

Amoco Canada Petroleum Company Ltd.

Canadian Occidental Petroleum Ltd.

Mobil Oil Canada, Ltd.

**North Canadian Marketing Inc. and East Georgia
Cogeneration (Vermont) Limited Partnership**

ProGas Limited

Shell Canada Limited

Unigas Corporation

Western Gas Marketing Limited

**Western Gas Marketing Limited, as agent for
Northern Minnesota Utilities, a Division of
UtiliCorp United Inc.**

**Applications Pursuant to Part VI of the National Energy Board
Act for Licences to Export Natural Gas**

GH-3-91

March 1992

**Volume II
Gas Exports**

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Recital and Appearances

IN THE MATTER OF the *National Energy Board Act*, and the regulations made thereunder;

AND IN THE MATTER OF applications by:

Amoco Canada Petroleum Company Ltd.;
 Canadian Occidental Petroleum Ltd.;
 Mobil Oil Canada, Ltd.;
 North Canadian Marketing Inc. and East Georgia Cogeneration (Vermont)
 Limited Partnership;
 ProGas Limited;
 Shell Canada Limited;
 Unigas Corporation;
 Western Gas Marketing Limited; and
 Western Gas Marketing Limited, as agent for Northern Minnesota Utilities,
 a Division of UtiliCorp United Inc.

for new gas export licences pursuant to section 117 of the *National Energy Board Act*;

AND IN THE MATTER OF Hearing Order AO-1-GH-3-91;

HEARD in Calgary, Alberta on 25, 26, and 27 June 1991.

BEFORE:

R. Illing
 W.G. Stewart
 C. Bélanger

Presiding Member
 Member
 Member

APPEARANCES:

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L.G. Keough

Northern Natural Gas Company

J.H. Smellie
 F. Horton

Northern States Power Company

K.L. Meyer

Pan-Alberta Gas Ltd.

(ii)

W.M. Moreland

Alberta Petroleum Marketing Commission

J. Syme
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National Energy Board

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Abbreviations

Act	<i>National Energy Board Act</i>
Alberta and Southern	Alberta and Southern Gas Company Ltd.
Amoco Canada	Amoco Canada Petroleum Company Ltd.
ANR Storage	ANR Storage Company
Bcf	billion cubic feet
Board or NEB	National Energy Board
CanadianOxy	Canadian Occidental Petroleum Ltd.
DCQ	Daily Contract Quantity
DOE/FE	(United States of America) Department of Energy, Office of Fossil Energy
EARP Order	<i>Environmental Assessment and Review Process Guidelines Order</i>
EGC	East Georgia Cogeneration (Vermont) Limited Partnership
EIA	Export Impact Assessment
Empire	Empire Energy Niagara Limited Partnership
Enron	Enron Gas Marketing, Inc.
ERCB	(Alberta) Energy Resources Conservation Board
FERC	(United States of America) Federal Energy Regulatory Commission
Foothills	Foothills Pipe Lines Ltd.
FS	Firm Service
Gas contract	contract for the purchase and sale of natural gas
GJ	gigajoule(s)
GLGT	Great Lakes Gas Transmission Limited Partnership
Harrison	Harrison Radiator Division of General Motors Corporation
LDC	local distribution company
Lockport Energy	Lockport Energy Associates, L.P.
MDQ	Maximum Daily Quantity
Midwest Gas	Midwest Gas, A Division of Iowa Public Service Company
MMBtu	million British thermal units
MMcf	million cubic feet

Mobil Canada	Mobil Oil Canada, Ltd.
NCMI	North Canadian Marketing Inc.
NEB or Board	National Energy Board
NGPL	Natural Gas Pipeline Company of America
Niagara Mohawk	Niagara Mohawk Power Corporation
NMU	Northern Minnesota Utilities, a Division of UtiliCorp United Inc.
Northern Border	Northern Border Pipeline Company
Northern Natural	Northern Natural Gas Company, a Division of Enron Corp.
NOVA	NOVA Corporation of Alberta
NSPW	Northern States Power Company, a Wisconsin corporation
NYSEG	New York State Electric and Gas Corporation
Part VI Regulations	<i>National Energy Board Part VI Regulations</i>
ProGas	ProGas Limited
PURPA	(United States of America) Public Utility Regulatory Policies Act of 1978
QF	qualifying cogeneration facility
Salmon	Salmon Resources Ltd.
Shell	Shell Canada Limited
Tennessee	Tennessee Gas Pipeline Company
TETCO	Texas Eastern Transmission Company
TransCanada	TransCanada PipeLines Limited
Unigas	Unigas Corporation
U.S.	United States of America
Vermont Gas	Vermont Gas Systems, Inc.
Viking	Viking Gas Transmission Company
VPSB	Vermont Public Service Board
WACOG	weighted average cost of gas
Western Gas	Western Gas Marketing Limited
WPSC	Wisconsin Public Service Commission

Chapter 1

Part VI - Gas Export Licence Applications

1.1 The Applications

During the GH-3-91 proceeding, the National Energy Board ("the Board") examined 12 applications for gas export licences. The applications were filed by the following companies:

1. Amoco Canada Petroleum Company Ltd. ("Amoco Canada") for export to Northern States Power Company, a Wisconsin corporation ("NSPW");
2. Canadian Occidental Petroleum Ltd. ("CanadianOxy") for export to NSPW;
3. Mobil Oil Canada, Ltd. ("Mobil Canada") for export to Northern Natural Gas Company, a Division of Enron Corp. ("Northern Natural");
4. North Canadian Marketing Inc. ("NCMI") and East Georgia Cogeneration (Vermont) Limited Partnership ("EGC") for export to EGC;
5. ProGas Limited ("ProGas") for export to Lockport Energy Associates, L.P. ("Lockport Energy");
6. ProGas for export to NSPW;
7. Shell Canada Limited ("Shell") for export to Salmon Resources Ltd. ("Salmon")/Midwest Gas, A Division of Iowa Public Service Company ("Midwest Gas") and Salmon/Enron Gas Marketing, Inc. ("Enron");
8. Unigas Corporation ("Unigas") for export to Northern Natural;
9. Western Gas Marketing Limited ("Western Gas") for export to Northern Natural;
10. Western Gas for export to Northern Minnesota Utilities, a Division of UtiliCorp United Inc. ("NMU");

11. Western Gas, as agent for NMU, for export to NMU; and
12. Western Gas for export to Vermont Gas Systems, Inc. ("Vermont Gas").

Table 1-1 provides a summary of each of the export licence applications reviewed during the GH-3-91 proceeding.

To accommodate those applicants who applied for licences to commence on 1 November 1991, the Board issued Volume I of its GH-3-91 Reasons for Decision in March 1992. Volume I dealt with the following applications:

- Mobil Canada for export to Northern Natural;
- Unigas for export to Northern Natural;
- Western Gas for export to Northern Natural;
- Western Gas for export to NMU;
- Western Gas as agent for NMU; and
- Western Gas for export to Vermont Gas.

The remaining six applications are dealt with herein. They are:

- Amoco Canada for export to NSPW;
- CanadianOxy for export to NSPW;
- NCMI/EGC for export to EGC;
- ProGas for export to Lockport Energy;
- ProGas for export to NSPW; and
- Shell for export to Salmon for resale to Midwest Gas and for export to Enron.

1.2 Market-Based Procedure

The Board, in considering an export application, must take into account section 118 of the *National Energy Board Act* ("the Act"), which requires that the Board have regard to all considerations that appear to it to be relevant and, in particular, that the Board satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

Table 1-1

Summary of Applied-for Licences

GH-3-91

Maximum Quantities Applied For

Application	Buyer (Type of market)	Term	Export Point	Daily 10 ³ m ³ (MMcf)	Annual 10 ⁶ m ³ (Bcf)	Term 10 ⁶ m ³ (Bcf)
1. Amoco Canada	NSPW (system supply)	1 Nov. 1992 to 31 Oct. 2002	Emerson, Manitoba	424.9 (15.0)	155.1 (5.5)	1 551.0 (54.8)
2. CanadianOxy	NSPW (system supply)	1 Nov. 1992 to 31 Oct. 2002	Emerson, Manitoba	212.5 (7.5)	77.5 (2.7)	775.5 (27.4)
3. Mobil Canada	Northern Natural (system supply)	GIC approval to 31 Oct. 2000	Emerson, Manitoba	563.5 (20.0)	205.7 (7.3)	2 056.9 (73.0)
4. NCMI/EGC	EGC (cogen. plant)	1 Nov. 1992 to 1 Nov. 2012	Philipsburg, Quebec	192.6 (6.8)	70.3 (2.5)	1 416.4 (50.0)
5. ProGas	NSPW (system supply)	1 Nov. 1992 to 31 Oct. 2002	Emerson, Manitoba	212.5 (7.5)	77.5 (2.7)	775.5 (27.4)
6. ProGas	Lockport Energy (cogen. plant)	1 Nov. 1992 to 31 Oct. 2007	Niagara Falls, Ontario	339.9 (12.0)	124.1 (4.4)	1 861.1 (65.7)
7. Shell (A)	Salmon/Midwest (system supply)	1 Nov. 1991 to 1 Nov. 2006	Monchy, Saskatchewan	580.7 (20.5)	212.5 (7.5)	3 181.2 (112.3)
Shell (B)	Salmon/Enron (system supply)	1 Nov. 1991 to 1 Nov. 2001	Monchy, Saskatchewan	277.6 (9.8)	102.0 (3.6)	1 014.1 (35.8)
8. Unigas	Northern Natural (system supply)	1 Nov. 1991 to 1 Nov. 2001	Monchy, Saskatchewan	2 820.0 (100.0)	1 030.0 (36.5)	10 300.0 (365.0)
9. Western Gas (A)	Northern Natural (system supply)	GIC approval to 31 Oct. 2001	Emerson, Manitoba	1 345.6 (47.5)	492.9 (17.4)	product of MDQ & days in term
Western Gas (B)	Northern Natural (system supply)	GIC approval to 31 March 1996	Emerson, Manitoba	1 416.4 (50.0)	170.0 (6.0)	849.8 (30.0)
Western Gas (C)	Northern Natural (system supply)	GIC approval to 31 Oct. 2001	Monchy, Saskatchewan	708.2 (25.0)	260.6 (9.2)	product of MDQ & days in term
10. Western Gas	NMU (system supply)	1 Nov. 1991 to 1 May 2001	Emerson, Manitoba	283.3 (10.0)	103.7 (3.6)	product of MDQ & days in term
11. Western Gas for NMU	NMU (system supply)	1 Nov. 1991 to 31 Oct. 2002	Sprague, Man. & Fort Frances, Ont.	1 059.5 (37.4)	388.1 (13.7)	4 270.0 (151.0)
12. Western Gas	Vermont Gas (system supply)	1 Nov. 1991 to 31 Oct. 2006	Philipsburg, Quebec	906.5 (32.0)	331.4 (11.7)	4 980.0 (176.0)

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. The following discussion of the Board's Market-Based Procedure is general in nature and applies to each of the export applications heard in the GH-3-91 proceeding.

The Market-Based Procedure provides that the Board consider:

- complaints, if any, under the complaints procedure;
- an export impact assessment ("EIA"); and
- any other factors that the Board considers relevant to its determination of the public interest.

In Proceeding GHW-1-91, the Board advised interested parties of proposed changes to be made to the Market-Based Procedure. These proposed changes affect the application of the Complaints Procedure and the other public interest considerations. Comments from parties were requested to be filed on 15 October 1991 with reply comment by 20 December 1991.

As the GHW-1-91 proceeding has not been completed, the Board has relied upon the existing procedure for its assessment of the applications heard in the GH-3-91 proceeding.

1.2.1 Complaints Procedure

When an application for an export licence is filed with the Board, interested parties have an opportunity to examine the various elements of the proposal. It is open to Canadian users of natural gas to come forward and object to the export on the ground that they cannot obtain additional supplies of gas under contract on terms and conditions, including price, similar to those in the export proposal.

There were no complaints made with respect to the applications for export licences in the GH-3-91 proceeding.

1.2.2 Export Impact Assessment

The purpose of the EIA is to assist the Board in determining whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. When the Market-Based Procedure was first introduced,

each export applicant was required to file an EIA assessing the impact of the proposed export on domestic natural gas supply, demand, and prices, and on the ability of Canadian energy markets to adjust to these changes without difficulty.

Pursuant to a review of EIA filing requirements conducted in the fall of 1989, the Board decided that, while it would retain the EIA as part of its Market-Based Procedure, it would conduct its own non-project-specific assessment. Applicants now have the option of using the Board's analysis or of preparing and submitting their own analysis as a basis for assessing whether the proposed exports would result in adjustment difficulties in Canadian energy markets.

The six applicants included in this Volume II adopted the Board's EIA.

In this regard, the Board believes that the applied-for export volumes would have little impact on the production, consumption, and price of gas in Canada, and that Canadian energy users would not experience difficulty in meeting their future energy requirements as a result of the proposed exports. The Board is also of the view that Canadian buyers of natural gas would not have significant problems adjusting to market forces that would result from approval of these exports.

1.2.3 Other Factors Relevant to the Public Interest

In addition to using the complaints procedure and the EIA to ascertain whether gas proposed to be exported is surplus, the Board continues, as required by section 118 of the Act, to have regard to all other factors it considers relevant in determining whether a proposed export is in the public interest.

In general, these factors can be placed into two categories: a) gas supply and b) market, commercial arrangements and regulatory status. This listing of factors that the Board may regard as relevant is illustrative rather than exhaustive, but the Board relies heavily on information filed by export licence applicants in accordance with the *National Energy Board Part VI Regulations* ("Part VI Regulations"). This information is used to assess whether an export proposal is in the public interest. The onus is on the applicant to

ensure that the filed material is such as to persuade the Board that the project has substance and is at a sufficiently advanced stage of completion to warrant the issuance of a licence.

1.2.3.1 Gas Supply

The Board conducts a review of the applicants' gas supply arrangements to assist it in determining whether the proposed exports are in the public interest. In its assessment of gas supply, the Board examines the contractual arrangements pertaining to supply, the adequacy of both reserves and productive capacity to support the applied-for exports, and the status of provincial removal authorizations.

The applicants provide estimates of remaining established reserves for those fields from which they intend to produce gas for the proposed export. The Board conducts geological and engineering analyses of the applicants' gas supply in order to prepare its own estimate of the applicants' marketable gas reserves.

In its evaluation of gas reserves, the Board makes use of its gas reserves database, which is maintained on an ongoing basis. The evaluation of gas reserves includes a nomenclature check for correlation purposes, volumetric studies of new pools, re-examination of developing pools and performance analysis of producing pools. A review and assessment of the ownership and contractual status of all pools included in the applications are also done.

The Board's estimate of reserves, along with basic deliverability data for each of the pools for which estimates of reserves were submitted, are used in preparing productive capacity projections. Productive capacity projections are generally adjusted to reflect an applicant's expected requirements for gas. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use the productive capacity resulting from an earlier excess of productive capacity over production. The requirements shown in the productive capacity figures are based on a load factor of 100 percent and may therefore somewhat overstate the applicants' actual supply requirements. To the extent that a lower load factor was anticipated, productive capacity would

be sustained beyond the time the Board's analysis indicates.

1.2.3.2 Market, Commercial Arrangements and Regulatory Status

The Board conducts a review of the market, commercial arrangements and regulatory status underpinning projects to assist it in determining whether the proposed exports are in the public interest. The applications dealt with in Volume II were for sales to three types of end-use markets: sales to local distribution companies ("LDCs"); sales to cogeneration facilities; and sales to a direct marketer. The Board's review of these market types included consideration of the following for each market type:

- for exports to LDCs for system supply, it included consideration of the LDCs' current and projected requirements and overall supply portfolio with a view to determining the need for and the role of the Canadian gas supply within that portfolio;
- for exports to a cogeneration facility, defined as a facility that produces electricity and thermal energy for use in commercial or industrial operations, an examination of the contractual chain, from the gas sales contract to the power and thermal sales contracts, was conducted. In this regard the Board looked to the status of project financing, construction schedules, and qualifying cogeneration facility ("QF") certification; and
- for exports to a direct marketer, it included an assessment of the overall demand for supplementary gas supplies in the United States of America ("U.S."); a review of gas requirements related to a specific market region; and the competitiveness of the proposed export relative to other natural gas supplies within the marketer's supply portfolio.

For each type of end-use market, the review included consideration, amongst other items, of the load factors at which the proposed exports are expected to flow and the status of all pertinent regulatory authorizations in Canada and in the U.S.

The Board's review of the commercial arrangements included consideration of information the applicants were required to file in accordance with the Part VI Regulations and in response to Board information requests issued during the course of the hearing. This information included the following:

- the status of upstream and downstream transportation arrangements including all transportation contracts, either in final form or as precedent agreements;
- the contractual obligations entered into between the Canadian sellers and the U.S. buyers, including executed gas sales contracts;
- any resale arrangements that occur beyond the international boundary sale point, where such arrangements have a direct effect on the international sales agreement, including filing of these downstream contracts; and
- in the case of cogeneration facilities, the contractual obligations entered into between the cogeneration facility and the electric utility and the steam host.

In its review of the gas sales contracts entered into between the Canadian sellers and the U.S. buyers, the Board made the following determinations:

- whether the contracts are likely to recover associated Canadian intraprovincial and interprovincial transportation costs;
- whether the contracts contain provisions which permit adjustments to reflect changing market conditions over the life of the contract;
- whether the contracts ensure that the volumes contracted for are likely to be taken; and
- whether the contracts have the support of the Canadian producer(s) supplying the gas to the export project.

With respect to the second of the factors listed above, that of contractual responsiveness to changing market conditions, the Board recognizes

that there may be cases where contracts are attractive to the parties involved, notwithstanding a lack of flexibility. In implementing the criterion relating to contract responsiveness, the Board operates on the presumption that, where contracts are freely negotiated at arm's length, they are in the public as well as private interest.

1.3 Sunset Clauses

It has generally been Board practice in issuing a gas export licence to set an initial term of the licence for a short period of time during which, if the export of gas commences, the licence becomes effective for the full period approved by the Board. This condition in the licence is referred to as a sunset clause because the licence would expire if exports had not commenced within a specified timeframe. Inclusion of the sunset clause is intended to limit outstanding licences to those for which the gas actually flows within a reasonable period after the decision. The Board questioned each applicant concerning the acceptability of a sunset clause in the applied-for licence and in each case the applicant indicated that the inclusion of a sunset clause would be acceptable.

1.4 Environmental Screening

On 8 February 1990, the Minister of Energy, Mines and Resources, the Honourable Jake Epp, wrote to the Board requesting clarification on how the Board complied or would comply with the *Environmental Assessment and Review Process Guidelines Order* ("EARP Order") in arriving at its decision to issue licences for the export of natural gas. In his response to the Minister, the Chairman of the Board advised that, in compliance with the EARP Order, the Board would be instituting a screening procedure to examine the potential environmental effects of each export proposal before the Board.

The purpose of the environmental screening is to enable the Board to reach one of the conclusions required by section 12 of the EARP Order. To that end, the Board held a written proceeding, pursuant to Hearing Order AO-1-GH-3-91, wherein it considered submissions from the applicants as well as submissions from interested parties to the GH-3-91 proceeding.

The applicants filed with the Board environmental information concerning the

potential environmental effects of their proposals and the social effects directly related to those environmental effects, including any effects that are external to Canadian territory.

Interested parties were served with the applicants' submissions and were provided with an opportunity to provide their views on the issues referred to in those submissions. The applicants were then afforded an opportunity to

reply to the written submissions from interested parties.

The Board has completed its environmental screenings and has concluded that, in respect of the export proposals of the applicants, the potentially adverse environmental effects and the social effects directly related thereto are insignificant or mitigable with known technology.

Chapter 2

Amoco Canada Petroleum Company Ltd.

2.1 Application Summary

By application dated 4 April 1991, Amoco Canada sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	- 10 years commencing the later of 1 November 1992 or the date of first deliveries of gas
Point of Export	- near Emerson, Manitoba
Maximum Daily Quantity	- $425 \times 10^3 \text{ m}^3$ (15.0 MMcf)
Maximum Annual Quantity	- $155 \times 10^6 \text{ m}^3$ (5.5 Bcf)
Maximum Term Quantity	- $1\,551 \times 10^6 \text{ m}^3$ (54.8 Bcf)
Tolerances	- 10 percent per day and 2 percent per year

The gas proposed for export would be supplied from uncontracted reserves owned by Amoco Canada. These reserves are located primarily in Alberta.

The proposed gas export would be transported on the NOVA Corporation of Alberta ("NOVA") system for delivery to the TransCanada PipeLines Limited ("TransCanada") system near Empress, Alberta. TransCanada would transport the gas to the international border near Emerson, Manitoba. The gas could then be transported on either the Viking Gas Transmission Company ("Viking") or the Great Lakes Gas Transmission Limited Partnership ("GLGT") systems for final delivery to NSPW.

The gas would be used by NSPW, an electricity and gas distribution company, for system supply.

2.2 Gas Supply

2.2.1 Supply Contracts

No gas supply contracts were required as Amoco Canada would supply the proposed export with gas from its own pools. The gas sales contract between Amoco Canada and NSPW allows for gas to be supplied from Amoco Canada's uncontracted reserves as opposed to from specific dedicated reserves.

2.2.2 Reserves

In order to demonstrate that it had uncontracted reserves available to support the proposed export, Amoco Canada submitted the (Alberta) Energy Resources Conservation Board's ("ERCB") estimate of established reserves for Amoco Canada's lands in the Ricinus Cardium Unit No. 1. This unit covers the southern two-thirds of the Ricinus Cardium A pool. The Board's estimate of established reserves is identical to the ERCB's estimate. A comparison of Amoco Canada's and the Board's estimates with the applied-for volume is shown in Table 2-1. The estimates of established reserves are approximately 84 percent greater than the proposed term volume.

The Ricinus Cardium A pool commenced oil production in 1969. In 1973, a gas cycling scheme was initiated to maintain pressure in the reservoir. Since gas injection commenced, approximately $7.3 \times 10^9 \text{ m}^3$ (258 Bcf) of gas has been cycled. Amoco Canada has now applied to the ERCB for concurrent production of the Ricinus Cardium Unit No. 1 because its studies suggest only marginal benefit from continued gas injection. A decision from the ERCB is pending.

2.2.3 Productive Capacity

Amoco Canada provided a detailed study of the Ricinus Cardium Unit No. 1 A pool which indicated that its share of the expected gas production would largely meet the applied-for export requirements. To the extent that the

Table 2-1

**Comparison of Estimates of Amoco Canada's Established Gas Reserves
With the Applied-for Term Volume**

10⁶m³ (Bcf)

Amoco Canada¹	NEB²	Applied-for Volume
2 854 (101)	2 854 (101)	1 551 (55)

1. As of 1 November 1990.

2. As of 31 December 1990.

export volumes would be supplied from Amoco Canada's available gas supply, Amoco Canada provided a gas supply/demand balance which showed a surplus, after allowing for the NSPW volumes throughout most of the proposed term. Amoco Canada stated that any shortfalls in gas supply would be addressed by developing additional reserves. In this regard, the Board notes that Amoco Canada's gas supply/demand balance includes neither probable reserves nor gas which may be released by aggregators after 1992. For these reasons, the Board recognizes that Amoco Canada's estimate of available gas supply could be increased.

2.3 Market, Commercial Arrangements and Regulatory Status

2.3.1 Market

As NSPW is the market for the applications by Amoco Canada, CanadianOxy and ProGas, the following discussion is generic to all three applications.

The gas proposed for export would be used as system supply by NSPW for distribution to customers in 54 communities in western

Wisconsin and the upper peninsula of Michigan. NSPW serves approximately 55,000 natural gas customers, 88 percent of whom are residential customers with the remainder being commercial and industrial customers.

NSPW intends to support its existing supply portfolio with 310 10⁶m³ (11.0 Bcf) per year of Canadian firm, long-term gas supplies. The Amoco Canada volumes would comprise 50 percent of that total while the CanadianOxy and ProGas volumes would each comprise 25 percent.

NSPW currently purchases approximately 420 10⁶m³ (14.8 Bcf) of natural gas per year, of which 330 10⁶m³ (11.7 Bcf) is obtained from U.S. producers on a short-term basis. NSPW also has available 54 10⁶m³ (1.9 Bcf) of gas through storage contracted from ANR Storage Company ("ANR Storage"), liquefied natural gas peak shaving plants and seasonal supply service from Northern Natural. NSPW intends to rely on the long-term Canadian gas to fill its storage capacity.

With respect to requirements, NSPW stated that it expected its sales to continue to expand by at least five percent per year for the next several years because of a relatively low saturation rate

in its existing markets and because of an active expansion program into new communities.

In 1990, NSPW's total end-use markets consumed $400 \times 10^6 \text{m}^3$ (14.1 Bcf) of gas. Sales to NSPW's residential market segment are anticipated to increase from $133 \times 10^6 \text{m}^3$ (4.7 Bcf) in 1991 to $190 \times 10^6 \text{m}^3$ (6.7 Bcf) by 2001. The commercial and firm industrial market segment is expected to grow from $113 \times 10^6 \text{m}^3$ (4.0 Bcf) in 1991 to $161 \times 10^6 \text{m}^3$ (5.7 Bcf) in 2001, while the interruptible market segment is projected to expand from $173 \times 10^6 \text{m}^3$ (6.1 Bcf) to $343 \times 10^6 \text{m}^3$ (12.1 Bcf) over the same period. NSPW projects that total demand in its end-use markets would increase to $694 \times 10^6 \text{m}^3$ (24.5 Bcf) by the year 2001.

NSPW anticipates that the gas proposed for export would be taken at a 70 percent load factor. This forecast is based upon the minimum purchase obligations provided for in the gas supply contracts and upon NSPW's market projections.

2.3.2 Transportation

The gas proposed for export would be transported by NOVA to the interconnection with TransCanada near Empress, Alberta for delivery to either Viking or GLGT near Emerson, Manitoba.

Amoco Canada has received confirmation that NOVA is prepared to transport the subject volumes upon receipt of regulatory approval to remove the gas from Alberta and upon the execution of NOVA transportation agreements.

As NSPW is arranging transportation on TransCanada, GLGT and Viking for all of the Amoco Canada, CanadianOxy and ProGas volumes, the following discussion applies to all three of these applications.

NSPW requested $845 \times 10^3 \text{m}^3$ per day (30.0 MMcf) of firm transportation service on TransCanada from the Alberta/Saskatchewan border to Emerson, Manitoba commencing 1 November 1992. The request was not included in TransCanada's 1992/1993 facilities application as neither NSPW's supply nor transportation arrangements were sufficiently advanced at that time. NSPW filed an application dated 5 June 1991 pursuant to section 71 of the Act asking the

Board to compel TransCanada to provide such transportation service. In addition, NSPW requested that it be included in TransCanada's queue for transportation service commencing in November 1993. NSPW would be responsible for demand charges on TransCanada.

On 25 September 1991, TransCanada filed revisions to its 1992/1993 facilities application. Included in these revisions was the addition of facilities necessary to deliver the export volumes to NSPW. The Board's decision with respect to TransCanada's 1992/1993 facilities application is pending.

NSPW has contracted for $317 \times 10^3 \text{m}^3$ per day (11.2 MMcf) of firm service on GLGT, and currently has $850 \times 10^3 \text{m}^3$ per day (30.0 MMcf) of high priority interruptible service on that system which it intends to reduce to $283 \times 10^3 \text{m}^3$ per day (10.0 MMcf) over the next few years. The GLGT system would also be used to transport the gas to ANR Storage and for backhaul to NSPW's market.

By letter dated 19 June 1991, GLGT advised NSPW that it would be filing applications pertaining to certain service restructurings which GLGT anticipated would obviate the need for facilities additions, and would permit service to NSPW to commence by 1 November 1991.

NSPW has $258 \times 10^3 \text{m}^3$ per day (9.1 MMcf) of firm and $127 \times 10^3 \text{m}^3$ per day (4.5 MMcf) of authorized overrun service on Viking on an annual basis. Nominations under the authorized overrun service would have priority over other interruptible service nominations. NSPW also has $229 \times 10^3 \text{m}^3$ per day (8.1 MMcf) of firm winter service on Viking.

NSPW would thus have firm and authorized overrun winter capacity for $845 \times 10^3 \text{m}^3$ per day (30.0 MMcf) of gas. For the balance of the year, NSPW would have under contract $578 \times 10^3 \text{m}^3$ per day (20.4 MMcf) of firm service and $977 \times 10^3 \text{m}^3$ per day (34.5 MMcf) of high priority interruptible service.

2.3.3 Gas Sales Contract

Amoco Canada and NSPW have entered into a gas sales contract dated 1 January 1991. The contract term extends for ten years from the commencement of deliveries and would continue

on a year-to-year basis thereafter. Firm deliveries are expected to commence 1 November 1992.

The contract contemplates a Maximum Daily Quantity ("MDQ") level of up to 425 10³m³ (15.0 MMcf) for deliveries at the interconnection of TransCanada with GLGT and Viking near Emerson, Manitoba.

The contract is subject to several conditions precedent, including the cessation of NSPW's purchase obligations under a contract with Amoco Production Company of the United States, receipt of all necessary Canadian and U.S. regulatory approvals and completion of all requisite Canadian and U.S. transportation arrangements. If the conditions precedent are not satisfied by 1 October 1992, the contract may be terminated.

Under the terms of the contract, NSPW would be obligated to pay Amoco Canada a deficiency charge of five percent of the commodity charge if minimum load factors (75 percent during winter months and 40 percent during summer months) are not satisfied. Further, if on a three-year rolling basis, NSPW nominates less than 55 percent of the MDQ on an annual basis, then Amoco Canada may reduce its delivery obligation to a level consistent with actual nominations.

The contract provides for a two-part price consisting of a demand charge component and a commodity charge component.

The demand charge component includes demand charges paid by Amoco Canada for transportation on NOVA and TransCanada plus a supply reservation charge of ten percent of the commodity charge.

The initial commodity charge component would be \$U.S. 1.35/GJ (\$U.S. 1.45/MMBtu). Thereafter, the commodity charge would be adjusted annually to reflect the following changes: spot gas purchase prices in Kansas, Texas and Oklahoma; the commodity charges for Canadian gas exported at Emerson, Manitoba for sales to the U.S. midwest; and NSPW's weighted average cost of gas ("WACOG") for firm supplies. The combined commodity and supply reservation charge would be capped at Northern Natural's tariff for firm service supply until 1 October 1995.

The commodity charge may be renegotiated in any year in which it falls outside of set market indicators selected by the parties. If the parties fail to agree upon a renegotiated charge, they may refer the matter to binding arbitration. Arbitration would be used to determine a price which accurately tracks prices in the midwestern U.S. Should arbitration of price negotiations be required twice during the contract term, then the contract can be terminated after a phase-down period. The phasing down of the contract can commence no earlier than the sixth year of the contract term.

The estimated price that would have been in effect under the terms of this contract at the Alberta border as of 1 March 1991 was \$ Cdn. 1.78/GJ (\$ Cdn. 1.91/MMBtu).

2.3.4 Regulatory Status

Amoco Canada applied to the ERCB for a removal permit on 18 April 1991. The ERCB decision was pending at the close of the hearing.

NSPW indicated that it intended to apply for (U.S.) Department of Energy, Office of Fossil Energy ("DOE/FE") import authorization in mid-July 1991.

The force majeure provisions of the gas sales contract provide that NSPW must receive approval from the Wisconsin Public Service Commission ("WPSC") to pass through to its customers all contractual costs. NSPW is required to submit its supply plans annually to the WPSC for discussion.

2.4 Views of the Board

The Board is satisfied with Amoco Canada's gas supply based on the specific pool information which has been submitted and the evidence of available supply from uncontracted reserves.

The Board is satisfied that the LDC market of NSPW represents a stable long-term market for Canadian gas. Amoco Canada's sales would represent less than 22 percent of NSPW's total annual requirements and, therefore, it is unlikely that changes in the LDC's overall demand would be reflected wholly upon sales by Amoco Canada. The Board notes that this sale is intended to

displace sales currently being made by Amoco Production Company of the United States.

While transportation on TransCanada has yet to be finalized, the Board notes that a decision regarding the facilities required to transport the export gas to NSPW is pending in another proceeding before the Board.

The Board is satisfied that the demand charge component of the price in the gas sales contract would ensure recovery of all fixed Canadian transportation costs.

In the Board's view, the contractual provisions regarding deficiency charges, supply reservation charges and demand charges would ensure adequate take levels under the gas sales contract.

The Board has reviewed the gas contract and notes that it has been negotiated at arm's length.

The Board notes that DOE/FE import authorization and approval of the gas sales contract by the WPSC remain outstanding, but is of the view that these are not likely to be an impediment to Amoco Canada's proposed export.

2.5 Decision

The Board has decided to issue a gas export licence to Amoco Canada, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 November 1992 or the date of first deliveries of gas and shall end on 1 November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the term would end ten years following its commencement.

Chapter 3

Canadian Occidental Petroleum Ltd.

3.1 Application Summary

By application dated 27 March 1991, CanadianOxy sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	- 10 years commencing the later of 1 November 1992 or the date of first deliveries
Point of Export	- near Emerson, Manitoba
Maximum Daily Quantity	- 213 10 ³ m ³ (7.5 MMcf)
Maximum Annual Quantity	- 78 10 ⁶ m ³ (2.7 Bcf)
Maximum Term Quantity	- 776 10 ⁶ m ³ (27.4 Bcf)
Tolerances	- 10 percent per day and 2 percent per year - volumes not exported during a year may be exported during the remaining term, subject to the annual and daily tolerances - the amount that may be exported may vary from the annual limitations necessitated by the actual heating conversion factor ¹

The gas proposed for export would be supplied from established reserves owned by CanadianOxy and located in Alberta.

The gas would be transported on the NOVA system for delivery to TransCanada's facilities near Empress, Alberta. TransCanada would transport the gas to the international border near Emerson, Manitoba where the gas would then be transported on either the Viking or GLGT systems for final delivery to NSPW. NSPW's transportation arrangements on TransCanada, GLGT and Viking are discussed in section 2.3.2 of these Reasons.

The gas would be used by NSPW, an electricity and gas distribution company, for system supply. Since November 1990, NSPW has been purchasing Canadian gas under short-term orders at approximately the same level as that applied for by CanadianOxy. A discussion of NSPW's

market is provided in section 2.3.1 of these Reasons.

CanadianOxy stated that the requested daily and annual tolerances were necessary to allow it to sell gas in excess of the daily contract quantity ("DCQ") on a best-efforts basis to NSPW while remaining within the requested term quantity.²

3.2 Gas Supply

3.2.1 Supply Contracts

Gas supply contracts were not necessary because CanadianOxy intends to supply the proposed export with its own gas from pools in Alberta. The Board notes that the gas sales agreement between CanadianOxy and NSPW includes a corporate warranty regarding CanadianOxy's supply obligation. This corporate warranty allows CanadianOxy to supply gas from its entire Alberta supply and requires that it pay any incremental costs incurred by NSPW for any alternative gas supplies needed to replace volumes not delivered by CanadianOxy. Although no specific pools have been contractually dedicated to the NSPW sale, CanadianOxy submitted a list of uncontracted pools from which it intends to provide the required volumes and which it expects to have included in its provincial removal permit.

3.2.2 Reserves

Table 3-1 shows that the Board's estimate of CanadianOxy's remaining marketable gas reserves is 16 percent less than CanadianOxy's estimate; nevertheless it is 39 percent greater than the applied-for volume.

1. CanadianOxy later submitted that the daily and annual tolerances would be sufficient to cover fluctuations in the heating conversion factor.
2. CanadianOxy later submitted that exporting this "best-efforts" gas under short-term orders would be an acceptable alternative.

Table 3-1

**Comparison of Estimates of CanadianOxy's Established Gas Reserves
With the Applied-for Term Volume**

10^6m^3 (Bcf)

CanadianOxy ¹	NEB ²	Applied-for Volume
1 291 (46)	1 081 (38)	775.5 (27)

1. As of 1 January 1991.

2. As of 31 December 1989. The Board's estimate of remaining reserves would be a minimum of $56 \times 10^6\text{m}^3$ (2 Bcf) less than shown if further adjusted for estimated production to 31 December 1990. The Board's estimate of reserves would then be 21 percent less than CanadianOxy's and 32 percent greater than the applied for volume.

CanadianOxy's estimate of reserves includes proven and probable reserves from both producing and non-producing properties in Alberta. The estimate of probable reserves accounts for nine percent of the total estimate. Most of the difference in the overall estimates of reserves is the result of differences in reserves determination methodology, interpretation of certain pool configurations and recovery factor estimates for the producing areas, in particular Decrene, Graham and Newby. The overall difference in reserves estimates for CanadianOxy's non-producing fields is small and due mainly to minor variances in estimates of area and net pay.

The difference between CanadianOxy's and the Board's estimates of reserves for Graham and Newby accounts for approximately 50 percent of the overall difference in estimates of total reserves. In these fields, the Board interprets that some of the larger pools, as defined by CanadianOxy and consisting of both proven and probable reserves, are actually subdivided into several smaller pools. As a result, the Board has recognized reduced pool areas and only proven reserves at this time. In addition, the Board has assigned a 50 percent recovery factor as proven

reserves to the pools it recognized, whereas CanadianOxy assigned similar recovery factors, which included both proven and probable reserves, but applied them over larger pool areas.

For the Decrene Clearwater A pool, the Board has a lower reserves estimate than CanadianOxy due to differences in reserves determination methodologies. The difference in estimates of reserves for this pool accounts for approximately 40 percent of the overall reserves difference.

In its assessment of CanadianOxy's submitted gas supply, the Board has recognized 36 pools located in Alberta, mainly in Lower Cretaceous and Devonian horizons. Twenty of these pools have estimates of reserves less than $100 \times 10^6\text{m}^3$ (3.5 Bcf), while only one pool has a reserve estimate greater than $500 \times 10^6\text{m}^3$ (17.6 Bcf). Eight pools were on production prior to 31 December 1989, while a total of 12 pools had been placed on production by 31 December 1990.

In summary, while the Board's estimate of reserves is less than CanadianOxy's estimate, it is substantially larger than the applied-for volume. The difference in estimates of reserves is due

principally to differences in reserves determination methodology, interpretation of the configuration of certain pools and assumptions on recovery factors for three of CanadianOxy's producing areas.

3.2.3 Productive Capacity

A comparison of both the Board's and CanadianOxy's projections of productive capacity with the applied-for requirements, including fuel on the NOVA and TransCanada systems, is shown in Figure 3-1.

CanadianOxy indicated that it could meet its annual requirements throughout the proposed term. The Board's projection suggests that deficiencies in productive capacity may commence during the 1997-1998 contract year. In order to address possible shortfalls in deliverability, CanadianOxy stated that it would rely on its total undedicated supply pool which totalled about $7.0 \times 10^9 \text{m}^3$ (247 Bcf) as of 1 January 1991.

3.3 Market, Commercial Arrangements and Regulatory Status

3.3.1 Market

A discussion of NSPW's market is presented in section 2.3.1 of these Reasons.

3.3.2 Transportation

The gas proposed for export would be transported by NOVA to the interconnection with TransCanada near Empress, Alberta for delivery to either Viking or GLGT near Emerson, Manitoba. NSPW's transportation arrangements on TransCanada, GLGT and Viking are described in section 2.3.2 of these Reasons.

CanadianOxy stated that it has, or would have, firm NOVA transportation to meet its initial contractual obligations to NSPW. Additional transportation on NOVA would be arranged as required.

3.3.3 Gas Sales Contracts

CanadianOxy and NSPW executed a gas sales contract dated 1 November 1990.

The contract provides for the daily delivery of up to $213 \times 10^3 \text{m}^3$ (7.5 MMcf) at the interconnection of the TransCanada system with the GLGT and Viking systems near Emerson, Manitoba.

The contract term extends for ten years from the commencement of deliveries. Deliveries under the contract are to commence no later than 1 November 1992 but could take place as soon as all conditions precedent are satisfied including receipt of Canadian and U.S. regulatory approvals and completion of all Canadian and U.S. transportation arrangements. If the conditions precedent are not satisfied by 30 September 1992, the contract may be terminated.

NSPW is obligated to pay an escalating charge, set initially at \$U.S. 0.23/GJ (\$U.S. 0.25/MMBtu), for deficient volumes in the event that the minimum annual load factor falls below 65 percent; load factor during the winter months falls below 75 percent; or, during the balance of the year, a load factor of at least 40 percent is not maintained. Further, should NSPW nominate less than 55 percent of the MDQ on a normalized three-year rolling basis, then CanadianOxy may reduce its delivery obligations to approximately one-half of the three-year rolling average of actual nominations.

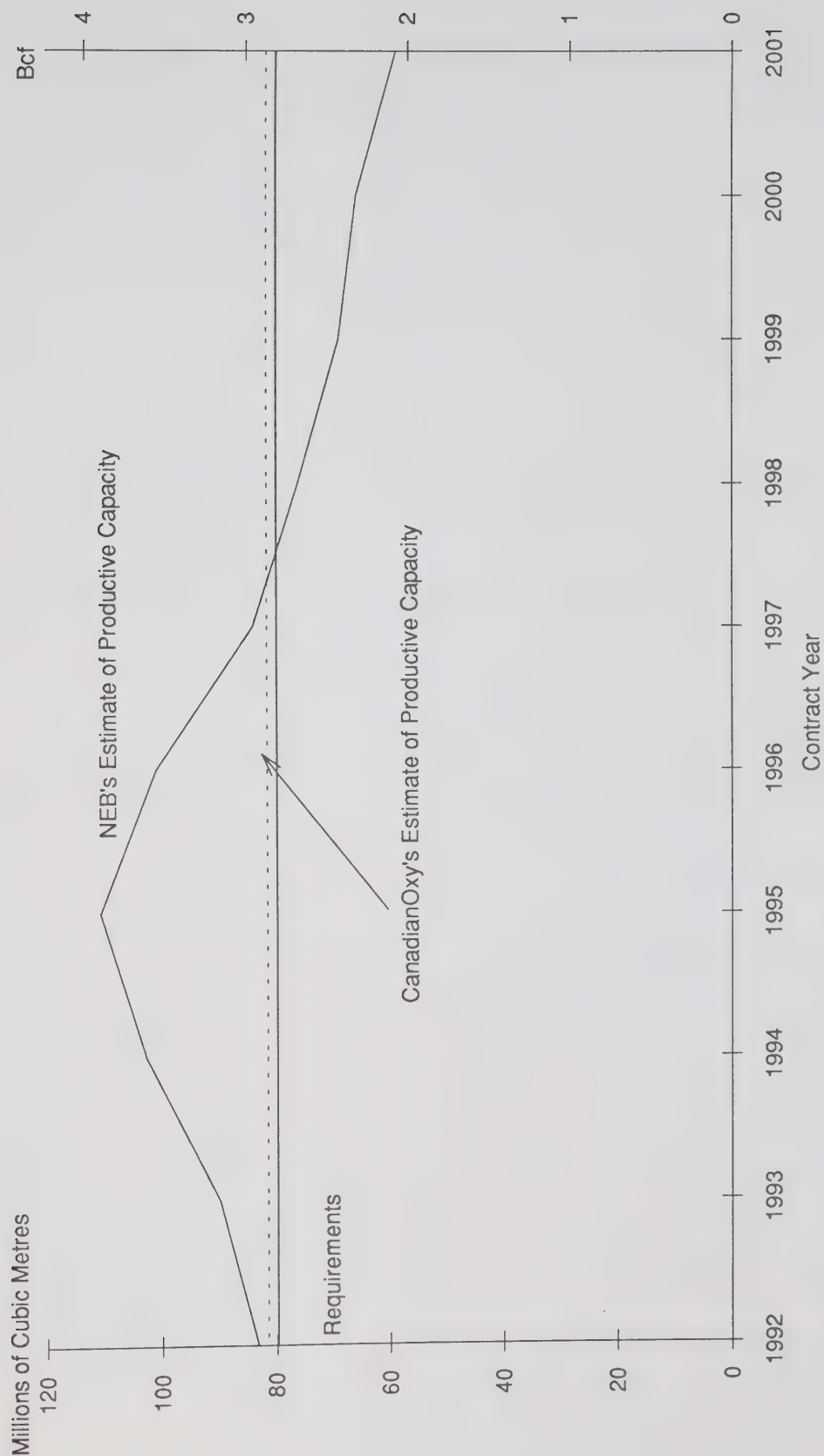
Under the terms of the contract, the price paid by NSPW would consist of a commodity charge component and a demand charge component. The demand charge component of the price would recover demand charges incurred for the transportation of the gas on the NOVA and TransCanada systems.

The base annual commodity charge has been set at \$U.S. 1.58/GJ (\$U.S. 1.70/MMBtu). The monthly commodity charge would be the product of the annual commodity charge and a monthly adjustment factor of between .8235 and 1.2353 which is intended to reflect seasonal variances. The annual commodity charge would be adjusted yearly to reflect changes in the WACOG of a number of selected utilities in five midwestern states.

Either party may request renegotiation of the commodity charge adjustment mechanism should the change in the commodity charge in any year fall outside of a set range. The sales contract also provides that twice during the contract term, the

Figure 3-1

COMPARISON OF CANADIANOXY'S & NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



level of the commodity charge can be renegotiated. The first request for such renegotiation cannot occur before 1 July 1995, while the second request may be made no sooner than three years following the first. In either case, failure to agree on a renegotiated price may be referred to binding arbitration. Arbitration would be used to determine a price which tracks prices in the midwestern U.S. and which maintains NSPW's WACOG relative to other utilities.

The estimated price that would have been in effect under the terms of this contract at the Alberta border as of 1 March 1991 was \$ Cdn. 1.81/GJ (\$ Cdn. 1.94/MMBtu).

3.3.4 Regulatory Status

CanadianOxy applied to the ERCB for a removal permit on 25 April 1991. The ERCB decision was pending at the close of the hearing.

NSPW indicated that it intended to apply for DOE/FE import authorization in mid-July 1991.

The force majeure provisions of the gas sales contract provide that NSPW must receive approval from the WPSC to pass through to its customers all contractual costs. NSPW is required to submit its supply plans annually to the WPSC for discussion.

3.4 Views of the Board

While the Board's estimate of reserves for the specific pools, submitted by CanadianOxy in support of its application, exceeds the applied-for volume, the Board's projection of productive capacity indicates that deficiencies relative to requirements may occur in the latter portion of the proposed export term. The Board has considered CanadianOxy's evidence regarding its undedicated corporate supply and is of the view that potential shortfalls in productive capacity could be remedied by utilizing productive capacity from CanadianOxy's corporate gas supply. The Board is therefore satisfied with the adequacy of CanadianOxy's supply.

With respect to the tolerances that CanadianOxy requested, the Board, in response to requests from applicants, has historically included daily and annual operating tolerances in order to accommodate divergences due to operational and

measurement discrepancies. Discrepancies due to variations in the heating conversion factor, for instance, are intended to be covered by the daily and annual tolerances. Daily and annual operating tolerances are not intended to be used to make up volumes that were not previously taken. The Board notes that CanadianOxy has stated that it would not have a problem exporting best-efforts gas under short-term orders, and that divergences in heating conversion factors can be accommodated under the standard daily and annual operating tolerances.

The Board is satisfied that NSPW's market represents a stable long-term market for Canadian gas. CanadianOxy's sales would represent less than 11 percent of NSPW's total annual requirements and, therefore, it is unlikely that changes in the LDC's overall demand would be reflected wholly upon CanadianOxy's sales. The Board notes that the long-term export licence is intended to replace an existing short-term export authorization under which gas is currently flowing to NSPW.

While transportation on TransCanada has yet to be finalized, the Board notes that a decision regarding the facilities required to transport the export gas to NSPW is pending in another proceeding before the Board.

The Board is satisfied that the demand charge component of the price in the gas sales contract would ensure recovery of all fixed Canadian transportation costs.

In the Board's view, the contractual provisions regarding deficiency charges, supply reservation charges, demand charges and CanadianOxy's option to reduce volumes should nominations not exceed 55 percent of the MDQ, would ensure adequate take levels under the gas sales contract. Finally, the Board has noted that the gas sales contract has been negotiated at arm's length.

The Board notes that DOE/FE import authorization and approval of the gas sales contract by the WPSC remain outstanding, but is of the view that these are not likely to be an impediment to CanadianOxy's proposed export.

3.5 Decision

The Board has decided to issue a gas export licence to CanadianOxy, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 November 1992 or the date of first deliveries of gas and shall end on 1 November 1994, unless exports have commenced under the licence on or before

1 November 1994, in which case the term would end ten years following its commencement.

The Board has decided not to include in the licence the tolerances requested by CanadianOxy to provide for make-up requirements and to accommodate differences due to heating conversion calculations. The Board considers that the normal daily and annual operating tolerances which are included in gas export licences would be adequate to meet both of these purposes.

North Canadian Marketing Inc. and East Georgia Cogeneration (Vermont) Limited Partnership

4.1 Application Summary

By the joint application dated 17 February 1991, NCMI/EGC applied pursuant to Part VI of the Act for a natural gas export licence with the following terms and conditions:

Term	- 1 November 1992 to 1 November 2012
Point of Export	- near Philipsburg, Quebec
Maximum Daily Quantity	- $192.5 \times 10^3 \text{ m}^3$ (6.8 MMcf)
Maximum Annual Quantity	- $70.3 \times 10^6 \text{ m}^3$ (2.5 Bcf)
Maximum Term Quantity	- $1\,410 \times 10^6 \text{ m}^3$ (50.0 Bcf)
Tolerances	- 10 percent daily - authorization to export volumes authorized but not taken in one year, over the remaining term of the licence, subject to the daily and annual limitations.

The gas proposed for export would originate from certain pools, fields or areas in Alberta. The gas is owned by NCMI's parent company, North Canadian Oils Limited, and would be sold to EGC for use in a cogeneration facility EGC intends to build in the State of Vermont.

The gas would be transported on the NOVA and TransCanada systems to the international border near Philipsburg, Quebec. At that point the proposed export would be sold to EGC and transported through Vermont Gas to the cogeneration facility located in the vicinity of Georgia Center, Vermont.

Following the close of the hearing, NCMI/EGC advised the Board that the Vermont Public Service Board ("VPSB") had denied EGC's application for a Certificate of Public Good for the proposed cogeneration facility and, as a result of this decision, the project had been delayed.

By letters dated 8 November 1991 and 22 November 1991 NCMI/EGC informed the Board of the following:

- an appeal by EGC of the VPSB decision had been filed with the Supreme Court of Vermont;
- EGC was negotiating with the Vermont Department of Public Service to reach agreement to allow a Certificate of Public Good to be issued;
- the reserves, reviewed in the GH-3-91 proceeding and dedicated by NCMI to the EGC project, had been withdrawn by NCMI with EGC's agreement;
- the same reserves had also been withdrawn from NCMI's application for an ERCB removal permit; and
- as soon as the EGC project has resolved its problems with the VPSB and is allowed to proceed, EGC will require NCMI to submit to the Board and to the ERCB substitute reserves acceptable to both regulatory bodies.

As a result of the foregoing, NCMI/EGC requested that the Board defer consideration of the applicants' application until such time as EGC could resolve its difficulties with the VPSB.

In its letter dated 5 December 1991, the Board advised NCMI/EGC that it would defer consideration of the NCMI/EGC Part VI application. The Board also advised that it had not made a decision with respect to the substitution of gas supply and that any decision required with respect to gas supply would be deferred until such time as the Board had a proposed supply package to consider.

Accordingly, NCMI/EGC's application will not be considered further until the applicants advise the Board that EGC has resolved the outstanding matters pertaining to the issuance of a Certificate of Public Good by the VPSB.

Chapter 5

ProGas Limited for Sale to Lockport Energy

5.1 Application Summary

By application dated 29 March 1991, ProGas applied, pursuant to Part VI of the Act, for a natural gas export licence with the following terms and conditions:

Term	- 15 years commencing on the later of 1 November 1992 or the date of first deliveries
Point of Export	- Niagara Falls, Ontario
Maximum Daily Quantity	- $340 \times 10^3 \text{ m}^3$ (12 MMcf)
Maximum Annual Quantity	- $124 \times 10^6 \text{ m}^3$ (4.4 Bcf)
Maximum Term Quantity	- $1\,861 \times 10^6 \text{ m}^3$ (65.7 Bcf)
Tolerances	- 10 percent per day and 2 percent per year

In the event that the Board should approve ProGas' application for a new licence, ProGas has also applied for an amendment, pursuant to subsection 21(2) of the Act, to gas export Licence GL-129. The effect of this proposed amendment would be to reduce the authorized licence levels in GL-129 by the equivalent level of the authorizations in the new licence. Specifically, ProGas proposed to amend condition 2 of Licence GL-129 is as follows:

- reduce the maximum volume in any consecutive 24-hour period to $2\,521.0 \times 10^3 \text{ m}^3$ (89.0 MMcf);
- reduce the maximum annual volume to $920.2 \times 10^6 \text{ m}^3$ (32.5 Bcf); and
- reduce the term volume to $13\,804.2 \times 10^6 \text{ m}^3$ (487.3 Bcf).

The proposed export volume would be produced from certain pools, fields and areas within Alberta and British Columbia. The gas would be transported on NOVA in Alberta and via TransCanada to the proposed export point at Niagara Falls, Ontario. In the U.S., Tennessee Gas Pipeline Company ("Tennessee") would transport the gas to Lockport, New York for use in Lockport Energy's cogeneration project. The bulk

of the electricity from the cogeneration facility would be sold to the New York State Electric and Gas Corporation ("NYSEG"). The facility will provide Harrison Radiator Division of General Motors Corporation ("Harrison") with all of its steam and electricity requirements.

5.2 Gas Supply

5.2.1 Supply Contracts

ProGas has acquired its gas supply primarily under two major purchase programs. The original program (ProGas I) was completed in 1978 and included roughly 110 gas purchase contracts executed with some 40 companies. The gas purchase contracts under the first program were 20-year reserves-based contracts providing for DCQs based on a rate-of-take of 1:7300 and MDQs established at 125 percent of the DCQs.

The second purchase program (ProGas II) was completed in 1981 and included approximately 460 gas purchase contracts executed with some 170 companies. These gas purchase contracts were also 20-year reserves-based contracts with DCQs based on a rate-of-take of 1:7300, but their MDQs were established at 133 percent of the DCQs.

Most recently, ProGas has added new reserves from Alberta and British Columbia to its supply pool. It has acquired these new reserves to help alleviate declining deliverability in producing pools and to offset reductions in reserves estimates due to both re-evaluations and the deferral of reserves which have now become uneconomic.

ProGas stated that as of 1 November 1991, it would be increasing the rate of take under all its gas purchase contracts to 1:5500 with MDQs of 125 percent of the DCQs.

5.2.2 Reserves

ProGas provided an estimate of the remaining established reserves it has under contract to meet

Table 5-1

**Comparison of Estimates of ProGas' Established Gas Reserves
With the Applied-for Term Volume**

10⁶m³ (Bcf)

ProGas¹	NEB²	Applied-for Volume³
102 020 (3 601)	86 218 (3 043)	1 861 (66)

1.Total remaining established gas reserves as of 31 December 1990.

2.Total remaining established gas reserves as of 31 December 1990. The Board has adjusted its estimate of remaining established gas reserves of 88 218 10⁶m³ (3 114 Bcf) as of 31 December 1989 to reflect estimated 1990 production of about 2 000 10⁶m³ (71 Bcf).

3.This represents less than two percent of ProGas' total requirements which are 78 892 10⁶m³ (2 785 Bcf).

both its existing commitments and the proposed export. Table 5-1 shows that the Board's estimate of ProGas' remaining marketable reserves is about 15 percent lower than ProGas' estimate. The Board's estimate is, however, 9 percent higher than ProGas' total requirements of 78 892 10⁶m³ (2 785 Bcf), which includes the 1 861 10⁶m³ (66 Bcf) of proposed exports.

The differences in reserves estimates arise primarily from differences in the geological and engineering assessment of reserves for specific pools. The Board's reserves estimates for a number of large and medium sized pools are lower than those of ProGas, in part because the performance data for some of these pools do not support ProGas' reserves estimates based on volumetric analyses. Other significant reasons for these differences relate to interpretation of various reservoir parameters. These differences represent approximately 60 percent of the overall difference in reserves estimates.

Some of the difference in reserves estimates results from ProGas coalescing several small pools into larger pools; this has the effect of increasing ProGas' overall estimate of reserves for those pools. The Board has reviewed the geological

interpretation for many of these coalesced pools and, in most cases was not able to agree with ProGas' assessment. This group of pools accounts for another 15 percent of the overall difference in reserves estimates.

The remainder of the difference in reserves estimates stems from the cumulative effect of other small differences in individual small pools, rather than a large difference in any one pool. These other differences relate primarily to the interpretation of such reservoir parameters as net pay and porosity.

In its review of ProGas' supply, the Board has recognized approximately 1 300 pools, all but one being in Alberta. These pools are scattered across most of the province and include all major producing horizons. Most of the pools are concentrated in the Cretaceous zones of central and east-central Alberta. Fifty-two percent of ProGas' reserves are found in roughly 92 large pools, each having initial established reserves in excess of 1 000 10⁶m³ (35 Bcf). Approximately 32 percent of the ProGas' pools are currently on production.

In summary, the Board's estimate of ProGas' reserves is lower than ProGas'. The variance in estimates of reserves arises primarily from differences in geological and engineering evaluations of specific pools.

5.2.3 Productive Capacity

Figure 5-1 compares both the Board's and ProGas' projections of total productive capacity with ProGas' estimated total requirements, including fuel and shrinkage. ProGas has estimated its annual requirements based on a 90 percent load factor. Both projections of productive capacity assume that annual production will be at the annual estimated level of requirements; however, the Board recognizes that ProGas may take gas at higher levels than those assumed using the 90 percent load factor.

Both the Board's and ProGas' projections of productive capacity demonstrate adequate gas supply to meet requirements at a 90 percent load factor throughout the proposed export term. If shortfalls were to occur, ProGas has pointed out that it has an ongoing program to replace declining pools and uneconomic reserves; furthermore, ProGas has executed several "best efforts" contracts with other aggregators and individual suppliers who are prepared to provide additional deliverability if required.

5.3 Market, Commercial Arrangements and Regulatory Status

5.3.1 Market

The proposed export would be used to fuel Lockport Energy's 168 MW QF facility located on a 15 acre parcel of land in the industrial complex of Harrison, located approximately 25 kilometers north-northeast of Buffalo, New York. Construction of the facility commenced in May 1991 and it is expected to be in commercial operation in November 1992. Financing for plant construction has been obtained from the Chase Manhattan Bank. When the cogeneration plant is in operation, the Lockport Energy consortium will fund project equity equal to 15 percent of construction costs to a maximum of \$US 33 million. The equity contribution will be

used to pay down a portion of the debt, with the remaining debt amortized over thirteen years.

Lockport Energy is located in NYSEG's service territory but it is remote from the main load centers. Because of limited NYSEG transmission, a portion of the cogeneration facility's output will be wheeled by the Niagara Mohawk Power Corporation ("Niagara Mohawk"). NYSEG is a major gas and electric utility serving some 726,000 residential, commercial and industrial customers in south-central, eastern and western New York State.

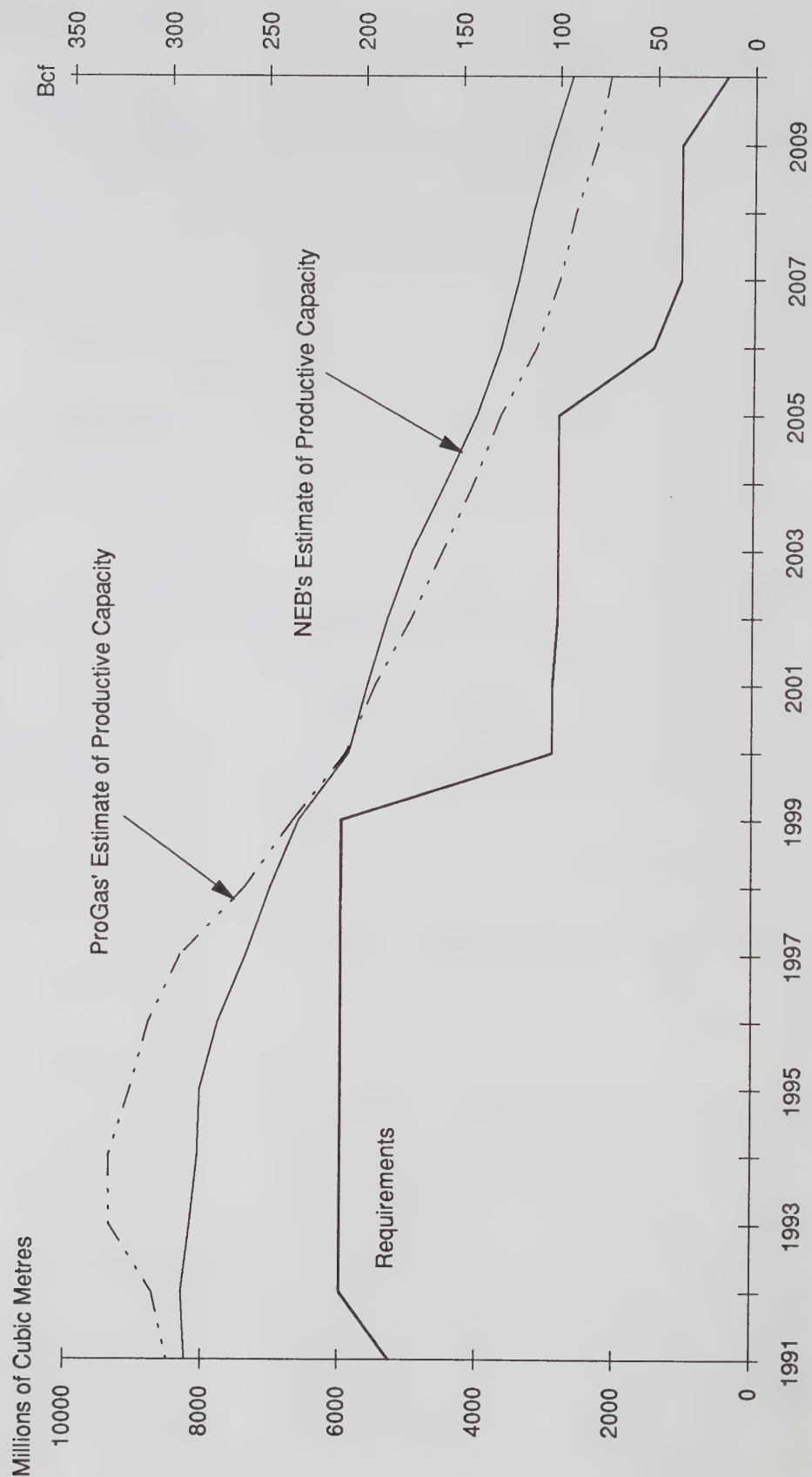
The thermal host, Harrison, employs approximately 7,000 people at its Lockport, New York complex. Harrison manufactures General Motors radiators, heaters, air conditioning systems, condensers and evaporators.

The cogeneration plant, generating approximately 1,460,000 MW.h of energy annually, is considered to be primarily a base-load plant. Because a maximum of 45 MW of capacity is available to NYSEG for economic dispatch, with up to 120 stops/starts for dispatchable capacity in any power year, subject to minimum shutdown and run times, NYSEG is unlikely to dispatch the plant off-line because it is obligated to pay for the power which could have been produced but was not taken. The marginal projected cost of 1.28¢/kW.h for 1993 is, according to Lockport Energy, low and there is no economic incentive for NYSEG to curtail. Further, the applicant stated that there is a continuing requirement for power in New York State, which could be served by cogeneration facilities.

The Lockport Energy facility, in providing Harrison with electricity, is displacing NYSEG sales. This is allowed under U.S. federal and state regulations because under the (United States of America) Public Utility Regulatory Policies Act of 1978 ("PURPA") a steam host is considered an integral part of a QF. Consequently, delivery of electricity to a thermal host, however paid for, cannot be defined as a retail sale because the federal exemption from state electric corporation regulation frees the electrical delivery from state scrutiny. As part of the relationship between thermal host and cogeneration developer, such electricity deliveries

Figure 5-1

COMPARISON OF PROGAS' & NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



are subsumed within the exemption from state regulation granted to a QF as a whole.

ProGas testified that it expects natural gas takes under the contract to be at a 90 percent load factor during the life of the contract.

5.3.2 Transportation

Within Canada the gas would be transported on NOVA and TransCanada under ProGas' existing transportation contracts with these pipelines.

In the U.S., Lockport Energy has signed a 20-year, firm transportation contract dated 14 March 1990 with Tennessee to transport the ProGas volumes using existing facilities.

5.3.3 Gas Sales Contract

A natural gas sales contract dated 22 February 1991 has been executed by ProGas and Lockport Energy and provides for the daily delivery of up to $339.9 \times 10^3 \text{ m}^3$ (12 MMcf) over a term of 15 years.

The contract is subject to several conditions precedent including the seller securing a finding of producer support, long-term transportation arrangements, a provincial removal permit, and an export licence; and the buyer securing U.S. import authorization.

The contract provides for a two-part price consisting of a demand charge component and a commodity charge component.

Lockport Energy will pay a monthly demand charge based on the full DCQ in effect for that month. The monthly demand charge will cover the fixed costs of transporting the gas on NOVA and TransCanada as well as a producer gas reservation charge based on the full DCQ equal to the effective adjusted base price multiplied by .11. The monthly gas reservation charge is payable regardless of the level of take.

The commodity charge was set initially at a base price of \$U.S. 1.68/MMBtu (\$U.S. 1.57/GJ) for the contract year commencing 1 November 1991 and is subject to annual increases of seven percent.

The estimated price that would have been in effect under the terms of this contract at the Alberta

border as of 1 March 1991 was \$Cdn 2.42/GJ (\$Cdn 2.60/MMBtu).

The contract provides for renegotiation of the pricing provisions prior to 1 November of any year and arbitration starting 1 November 1998 if a mutually acceptable price cannot be negotiated.

The contract also stipulates that in the event that Lockport Energy fails to purchase 80 percent of the annual DCQ, it is obligated to pay ProGas a non-take payment equivalent to the average commodity charge times the annual average prime interest rate plus one percent on deficient volumes. Lockport Energy does have a deficiency volume make-up provision in the year following the year in which the deficiency occurred.

The contract provides that Lockport Energy must purchase ProGas' gas on a pro rata basis with purchases from Lockport Energy's other sources.

5.3.4 Power Purchase Agreement

The proposed sale of electricity from the Lockport Energy plant will be pursuant to the power purchase agreement dated 26 March 1990, as amended, between NYSEG and Empire Energy Niagara Limited Partnership ("Empire"). The agreement was subsequently assigned by Empire to Lockport Energy. The agreement will continue for a period of 15 years from the commencement of commercial operations.

The contract includes dispatch provisions by NYSEG for up to 45 MW. The dispatch procedures are detailed in section 5.3.1 of these Reasons. The price to be paid for the electricity is a contractually predetermined stream of payments negotiated on a kilowatt-hour basis incorporating capacity and energy charges. Should any excess energy be produced, a separate rate for energy is provided for. The contract includes minimum capacity factors for the summer/winter periods with penalty charges for failure to maintain capacity at the minimum rates. For the 45 MW of dispatchable capacity, NYSEG pays Lockport Energy for the energy that was available but not delivered. NYSEG is not required to purchase from Lockport Energy, pursuant to its PURPA rights, when costs to NYSEG are greater than if NYSEG produced the power itself. NYSEG may take possession and operate the plant if Lockport Energy fails or

should be unable to operate the facility. The utility has first option after Harrison to purchase the plant should Lockport Energy propose to sell it.

5.3.5 Transmission Services Agreement

As described previously, a portion of the cogeneration facility's output requires transmission wheeling. A transmission services agreement, executed 11 April 1991, was entered into between Niagara Mohawk and Lockport Energy. The initial wheeling contract demand of 110 MW may be adjusted annually but is not to rise above 150 MW. Revisions thereafter may increase contract demand by 2 percent but in no event is Niagara Mohawk obligated to provide capacity in excess of 195 MW. Transmission rates are under the regulation of the (United States of America) Federal Energy Regulatory Commission ("FERC"). The wheeling agreement will continue for a period of 20 years from the commercial operation date.

5.3.6 Thermal Energy Sales Agreement

The Lockport Energy project will provide Harrison with steam and electricity. In response to a Board information request the applicant stated that its contract with Harrison is not intended to be made public. The applicant stated that the energy services agreement contains a 15-year minimum steam take obligation by Harrison of 700 million pounds annually. A minimum steam take of 300 million pounds per year is required to maintain the facility's PURPA QF status.

5.3.7 Regulatory Status

ProGas applied to the ERCB on 2 May 1991 to amend its existing Removal Permit GR 86-71 to reduce the Texas Eastern Transmission Company ("TETCO") market requirements and to add the Lockport Energy market.

A finding of producer support was issued by the Alberta Petroleum Marketing Commission on 2 April 1991.

Lockport Energy filed an application for DOE/FE import authorization on 24 June 1991 for a minimum of 15 years.

The cogeneration facility received QF status from the FERC on 17 November 1988.

5.4 Views of the Board

The Board's estimate of ProGas' reserves exceeds ProGas' total requirements, including the proposed exports and the Board's projection of productive capacity suggests no potential deficiencies. Accordingly, the Board is satisfied with the adequacy of ProGas' gas supply relative to its overall requirements including its proposed exports.

The Board notes that in its application to export gas to Lockport Energy, ProGas would utilize volumes that have already been authorized for export to TETCO under Licence GL-129 and that should the Board approve the applied-for export, ProGas has requested an amendment to that licence effective the first date of deliveries to Lockport Energy which would reduce the authorized levels under Licence GL-129 by the equivalent level of the authorizations being sought for the export to Lockport Energy.

The Board notes that financing for the plant has been secured and that construction commenced in May 1991.

Having reviewed the terms and conditions of the gas sales contract executed by ProGas and Lockport Energy, the Board is satisfied that the demand charge component of the export price would recover all fixed costs of transportation in Canada. The commodity component of the price escalates by seven percent per year from a base price set effective 1 November 1991. The contract provides for annual renegotiation of the pricing provisions and, if necessary, arbitration commencing 1 November 1998. The Board is satisfied that the export contract contains provisions which permit adjustments to reflect changing market conditions over the life of the contract. The Board is also satisfied that the gas sales contract was negotiated at arm's length.

The contract provides for a minimum take provision as well as pro-rationing of all sources of supply in the event that Lockport Energy's total

requirements are less than expected. In addition, the Board notes that the monthly gas reservation charge and, as previously mentioned, the Canadian demand charges would be paid regardless of take. For these reasons, the Board is satisfied that there is a reasonable assurance that the proposed export would operate at a high load factor.

The Board notes that the cogeneration plant has received QF status, an application to amend the Alberta removal permit will be made and an application for import authorization has been filed.

Finally, the Board also notes that the Alberta producers supplying gas to the proposed project have approved the terms and conditions of the sales contract.

5.5 Decision

The Board has decided to issue a gas export licence to ProGas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1992 and shall end on 1 November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the term would end on 1 November 2007.

In addition, the Board has decided to issue an order, subject to the approval of the Governor in Council, amending condition 2 of Licence GL-129 such that the quantity of gas that may be exported under the authority of that licence shall be reduced. See Appendix I for further details.

Chapter 6

ProGas Limited for Sale to NSPW

6.1 Application Summary

By application dated 27 March 1991, ProGas applied to the Board, pursuant to Part VI of the Act, for a licence to export natural gas with the following terms and conditions:

Term	- 10 years commencing the later of 1 November 1992 or the date of first deliveries
Point of Export	- near Emerson, Manitoba
Maximum Daily Quantity	- $212 \times 10^3 \text{ m}^3$ (7.5 MMcf)
Maximum Annual Quantity	- $78 \times 10^6 \text{ m}^3$ (2.7 Bcf)
Maximum Term Quantity	- $775 \times 10^6 \text{ m}^3$ (27.4 Bcf)
Tolerances	- 10 percent per day and 2 percent per year

The gas proposed for export would be produced from certain pools, fields and areas within the Provinces of Alberta and British Columbia.

The gas proposed for export would be transported on the NOVA system for delivery to TransCanada's facilities near Empress, Alberta. TransCanada would transport the gas to the international border near Emerson, Manitoba. The gas could then be transported on either the Viking or GLGT systems for final delivery to NSPW.

The gas would be used by NSPW, an electricity and gas distribution company, for system supply. NSPW has been purchasing approximately the same volume of gas as that being applied-for from ProGas under short-term permits since November 1990.

6.2 Gas Supply

A discussion of ProGas' gas supply is presented in section 5.2 of these Reasons.

6.3 Market, Commercial Arrangements and Regulatory Status

6.3.1 Market

A discussion of NSPW's market is presented in section 2.3.1 of these Reasons.

6.3.2 Transportation

The gas proposed for export would be transported by NOVA to the interconnection with TransCanada near Empress, Alberta for delivery to NSPW near Emerson, Manitoba. NSPW's transportation arrangements on TransCanada, GLGT and Viking are discussed in section 2.3.2 of these Reasons.

ProGas has received confirmation that NOVA is prepared to transport the subject volumes upon receipt of regulatory approval to remove the gas from Alberta and upon the execution of transportation agreements with NOVA.

6.3.3 Gas Sales Contracts

ProGas and NSPW executed a contract dated 1 November 1990. The provisions of this contract are very similar to those in the CanadianOxy/NSPW contract except for the inclusion of a demand toll for ProGas' monthly services, differences in supply warranties and a provision for recourse in the event that the seller is unable to deliver the nominated volumes.

The contract provides for the daily delivery of up to $213 \times 10^3 \text{ m}^3$ (7.5 MMcf) at the interconnection of the TransCanada, GLGT and Viking systems near Emerson, Manitoba.

The contract term extends for ten years from the commencement of deliveries. Deliveries under the contract are to commence no later than 1 November 1992 but could take place as soon as all conditions precedent are satisfied including receipt of Canadian and U.S. regulatory approvals

and completion of all Canadian and U.S. transportation arrangements. If the conditions precedent are not satisfied by 30 September 1992, the contract may be terminated.

NSPW is obligated to pay an escalating charge, set initially at \$U.S. 0.23/GJ (\$U.S. 0.25/MMBtu), for deficient volumes if the minimum annual load factor falls below 65 percent, if the load factor during the winter months falls below 75 percent, or if during the balance of the year a load factor of at least 40 percent is not maintained. Further, should NSPW nominate less than 55 percent of the MDQ on a normalized three-year rolling basis, then ProGas may reduce its delivery obligations to approximately one-half of the three-year rolling average of actual nominations.

Under the terms of the contract, the price paid by NSPW would consist of a commodity charge component and a demand charge component. The demand charge component of the price would recover demand charges incurred for transportation of the gas on NOVA and TransCanada.

The base annual commodity charge has been set at \$U.S. 1.58/GJ (\$U.S. 1.70/MMBtu). The monthly commodity charge would be the product of the annual commodity charge and a monthly adjustment factor of between .8235 and 1.2353 which is intended to reflect seasonal variances. The annual commodity charge would be adjusted yearly to reflect changes in the WACOG of a number of selected utilities in five midwestern states.

Either party may request renegotiation of the commodity charge adjustment mechanism should the change in the commodity charge in any year fall outside of a set range. As well, twice during the contract term the level of the commodity charge can be renegotiated. The first request for such renegotiation cannot occur before 1 July 1995, while the second request may be made no sooner than three years following the first request. In either case, failure to agree on a renegotiated price may be referred to binding arbitration which is intended to yield a price that reflects spot gas sales into the U.S. midwest market, long-term exports from Alberta into the midwest market, and NSPW's WACOG relative to other midwestern utilities.

The estimated price that would have been in effect under the terms of this contract at the Alberta border as of 1 March 1991 was \$Cdn. 2.18/GJ (\$Cdn. 2.33/MMBtu).

6.3.4 Regulatory Status

On 2 May 1991, ProGas applied to the ERCB for addition of the NSPW market to its removal permit GR 86-71. The ERCB decision was pending at the close of the hearing.

A finding of producer support was issued by the Alberta Petroleum Marketing Commission on 17 December 1990.

NSPW indicated that it intended to apply for DOE/FE import authorization in mid-July 1991.

The force majeure provisions of the gas sales contract provide that NSPW must receive approval from the WPSC to pass through to its customers all contractual costs. NSPW is required to submit its supply plans annually to the WPSC for discussion.

6.4 Views of the Board

The Board's estimate of ProGas' reserves exceeds ProGas' total requirements, including the proposed exports and the Board's projection of productive capacity suggests no potential deficiencies. Accordingly, the Board is satisfied with the adequacy of ProGas' gas supply relative to its overall requirements including its proposed exports.

The Board is satisfied that the LDC market of NSPW represents a stable long-term market for Canadian gas. ProGas' sales would represent less than 11 percent of NSPW's total annual requirements and, therefore, it is unlikely that changes in the LDC's overall demand would be reflected wholly upon the sales by ProGas. The Board notes that the long-term export licence is intended to replace an existing short-term export authorization under which gas is currently flowing to NSPW.

While transportation on TransCanada has yet to be finalized, the Board notes that a decision regarding the facilities required to transport the export gas to NSPW is pending in another proceeding before the Board.

The Board is satisfied that the demand charge component of the price in the gas sales contract would ensure recovery of all fixed Canadian transportation costs.

In the view of the Board, the contractual provisions regarding deficiency charges, supply reservation charges, demand charges and ProGas' option to reduce volumes should nominations not exceed 55 percent of the MDQ would ensure adequate take levels under the gas sales contract.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length. The Board also notes that the producers supplying gas to the proposed sale by ProGas to NSPW have voted in favour of this arrangement.

The Board notes that DOE/FE import authorization and approval of the gas sales contract by the WPSC remain outstanding, but is of the view that these are not likely to be an impediment to ProGas' proposed export.

6.5 Decision

The Board has decided to issue a gas export licence to ProGas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 November 1992 or the date of first deliveries and shall end on 1 November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the term would end ten years following its commencement.

Chapter 7

Shell Canada Limited

7.1 Application Summary

By application dated 9 April 1991, as amended, Shell sought approval of two natural gas export licences. The first is for Shell's sale to Salmon for resale to Midwest Gas, and the other is for Shell's sale to Salmon for resale to Enron. The requested terms and conditions are as follows:

1. Salmon/Midwest Gas

Term	- Commencing on the later of 1 November 1991; the in-service date of applicable pipeline facilities; or the date upon which all precedent conditions are satisfied or waived and ending on the fifteenth November first following the commencement date.
Point of Export	- Monchy, Saskatchewan
Maximum Daily Quantity	- $580 \times 10^3 \text{ m}^3$ (20.5 MMcf)
Maximum Annual Quantity	- $212 \times 10^6 \text{ m}^3$ (7.5 Bcf)
Maximum Term Quantity	- $3\,181 \times 10^6 \text{ m}^3$ (112.3 Bcf)
Tolerances	- 10 percent per day and 2 percent per year.

2. Salmon/Enron

Term	- Commencing on the later of 1 November 1991; the in-service date of applicable pipeline facilities; or the date upon which all precedent conditions are satisfied or waived and ending on the tenth November first following the commencement date.
Point of Export	- Monchy, Saskatchewan
Maximum Daily Quantity	- $278 \times 10^3 \text{ m}^3$ (9.8 MMcf)
Maximum Annual Quantity	- $102 \times 10^6 \text{ m}^3$ (3.6 Bcf)
Maximum Term Quantity	- $1\,014 \times 10^6 \text{ m}^3$ (35.8 Bcf)
Tolerances	- 10 percent per day and 2 percent per year.

The proposed export volumes would be produced from certain pools, fields and areas within the province of Alberta. The gas would be transported in Alberta on NOVA to McNeil, Alberta on the Alberta/Saskatchewan border and then on Foothills Pipe Lines Ltd. ("Foothills") to the interconnection with Northern Border Pipeline Company ("Northern Border") near Monchy, Saskatchewan on the international border where it would be sold to Salmon. From this point, the gas would be transported to the interconnection with Northern Natural near Ventura, Iowa where it would be resold to Midwest Gas and Enron. The Midwest Gas volumes would be transported on Northern Natural to Midwest Gas' system for use as system supply. The Enron volumes would be transported on either the Northern Natural or Natural Gas Pipeline Company of America ("NGPL") pipeline systems to Enron's various markets.

7.2 Gas Supply

7.2.1 Supply Contracts

In order to meet the requirements of these proposed two export sales and other sales, Shell will provide gas from its own pools as well as purchase small volumes from other producers. Shell has executed gas purchase contracts with six producers, namely: Grad & Walker Resources Ltd., Drillwest Energy Marketing Inc., MLC Oil and Gas Ltd., Paloma Petroleum Ltd., Shaman Energy Corporation, and Voyager Energy Inc. The terms of the contracts range from two to five years with options to renew on a year-to-year basis.

7.2.2 Reserves

Shell's gas supply consists of reserves owned by Shell and gas purchased from other producers. The purchased supply accounts for five percent of Shell's estimate of total supply. Shell has purchased this gas for deliverability purposes until its unconnected pools are brought onstream.

Table 7-1

**Comparison of Estimates of Shell's Established Gas Reserves
With the Applied-for Term Volume**

10^6m^3 (Bcf)

	Shell ¹	NEB ¹	Applied-for Volume ²
Midwest			3 181 (112.3)
Enron			<u>1 014</u> (35.8)
Total	41 506 (1 465)³	37 514 (1 324)³	4 195 (148.1)

1. As of 1 November 1990.

2. These volumes represent only a portion of Shell's total commitments which must be supplied from these reserves. Shell's total commitments including the new volumes for Midwest Gas and Enron are $33\,158\,10^6\text{m}^3$ (1 171 Bcf).

3. This supply includes $2\,025\,10^6\text{m}^3$ (71.5 Bcf) of purchased gas.

Shell's estimate of reserves includes both proven and probable reserves, although probable reserves account for less than two percent of the total estimate.

Table 7-1 shows that the Board's estimate of Shell's remaining marketable gas reserves is ten percent lower than Shell's own estimate, and that both are considerably larger than the applied-for volume. The Board notes that the volumes under consideration for these proposed exports are only a portion of Shell's total commitments. The Board's estimate of Shell's reserves is 13 percent higher than Shell's total commitments.

In order to meet the incremental requirements of the Enron and Midwest Gas exports, Shell has revised its previously existing aggregate gas supply portfolio. These revisions include: additional pools, changes to reserves for some other pools, and reserves which were expected to be decontracted from Alberta and Southern Gas Company Ltd. ("Alberta and Southern"). The Board's estimate of reserves for this revised supply is 90 percent of Shell's estimate as noted in Table 7-1.

Differences in estimates of reserves are found mainly in the Progress, Limestone, Cordel and South Hamburg areas.

For the Progress area reserves, the differences in estimates are due primarily to differences in estimates of area for both single-well and multi-well pools.

The Limestone and Cordel areas contain reserves in Mississippian thrust fault structures. The South Hamburg area contains reserves in Devonian Slave Point and Watt Mountain reef traps. Most of the difference in the reserves estimates for these pools is due to differences in the interpretation of net pay based on log analysis.

Shell's decontracted gas supply consists of reserves from the Waterton Rundle J pool, a Mississippian thrust fault structure. Shell will be decontracting the pool from Alberta and Southern. The Board's estimate of reserves for the Rundle J pool is 17 percent smaller than Shell's estimate. The difference in estimates is due to differences in area and net pay as a result of different mapping styles.

The purchased gas supply accounts for five percent of Shell's total supply. The Board accepted Shell's estimates of reserves for these contracted volumes.

In its assessment of the applications, the Board recognized gas reserves for 145 pools located in 36 fields. Shell owns 33 of these pools with the remainder of the pools representing purchased gas. The majority of the pools are found in Lower Cretaceous horizons whereas most of the reserves are found in Mississippian and Devonian horizons. The Board's analysis indicated that 94 pools contain reserves of less than $100 \times 10^6 \text{m}^3$ (3.5 Bcf) and 12 pools contain reserves of more than $1\,000 \times 10^6 \text{m}^3$ (35 Bcf). Two of these 12 pools were found to contain more than $10\,000 \times 10^6 \text{m}^3$ (353 Bcf). These large pools, owned by Shell, represent 80 percent of the net remaining reserves. Fifty-two pools were on production by 1 January 1990.

In summary, the Board's estimate of reserves is smaller than Shell's estimate, but is larger than the total volumes required for Shell's existing commitments and the new volumes required for the proposed Midwest Gas and Enron sales.

7.2.3 Productive Capacity

A comparison of the Board's and Shell's projections of productive capacity with Shell's total requirements, including fuel and shrinkage, is shown in Figure 7-1.

Both the Board's and Shell's projections include expected productive capacity from the purchased reserves and additional deliverability of $566 \times 10^3 \text{m}^3$ per day (20 MMcfd) which Shell can take from Waterton under an agreement with Alberta and Southern. Figure 7-1 indicates that Shell will be able to meet its total requirements with a possible minor deficiency in projected productive capacity during 1998. Shell stated that it could alleviate any potential shortfalls in productive capacity by drawing gas from other properties it owns or by purchasing additional gas reserves.

7.3 Market, Commercial Arrangements and Regulatory Status

7.3.1 Markets

Shell has applied to export gas for sale to Salmon, a wholly-owned subsidiary of Shell, engaged in the import, purchase and resale of natural gas in various U.S. markets. Salmon will in turn resell the gas at Ventura, Iowa to two customers, Midwest Gas and Enron.

7.3.1.1 Midwest Gas Market

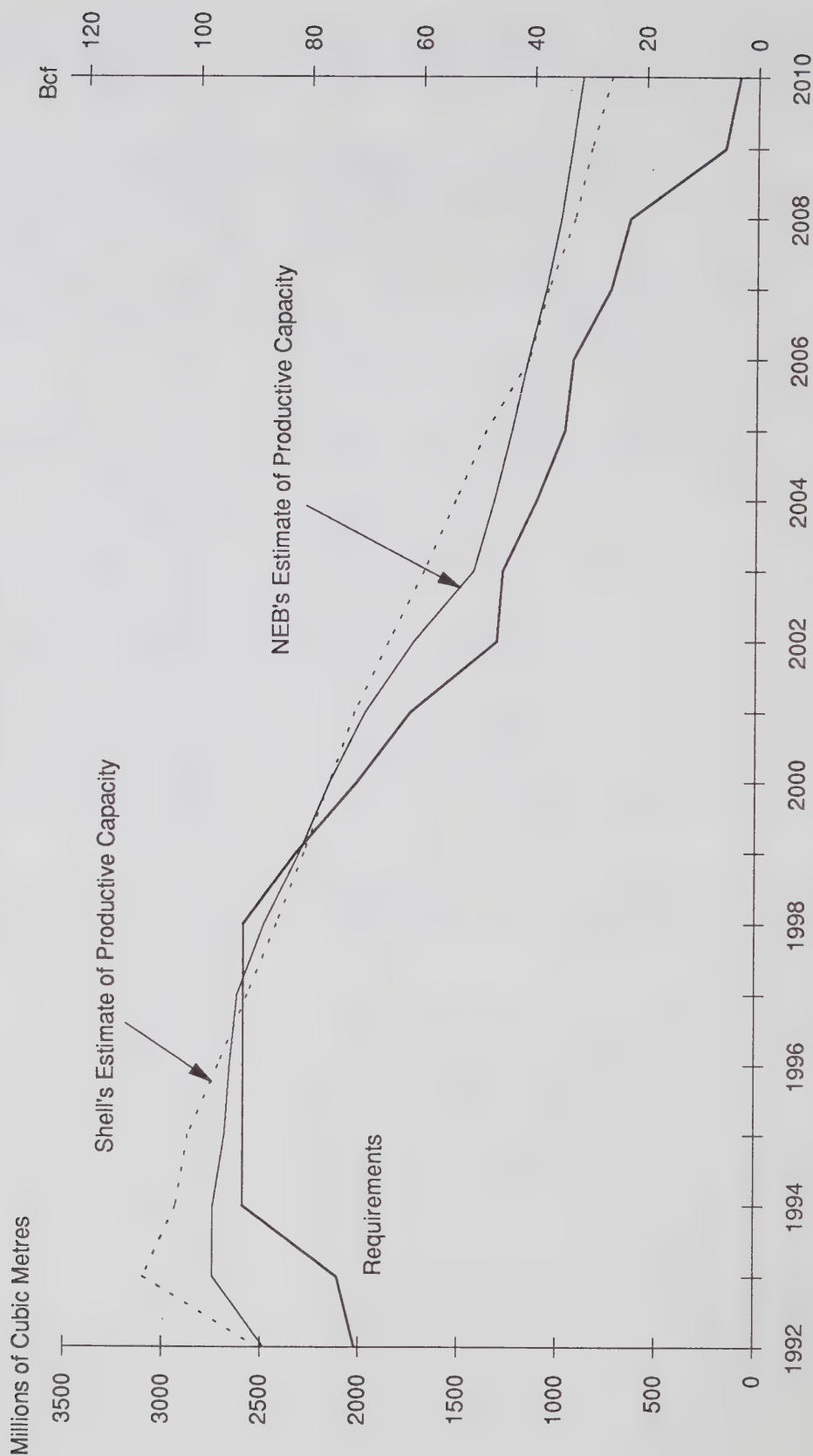
Midwest Gas is a transmission and distribution company operating in the midwestern U.S. It is the natural gas division of Iowa Public Service Company, a regulated public utility which also operates an electric utility in Iowa and South Dakota. Midwest Gas operates 11,000 miles of distribution mains serving approximately 356,000 customers in Iowa, Minnesota, South Dakota and Nebraska. During 1990, Midwest Gas' residential customers accounted for approximately 53 percent of its total natural gas sales by volume, while commercial and industrial customers accounted for 31 percent and 16 percent respectively. Midwest Gas also provided transportation service of $275 \times 10^6 \text{m}^3$ (9.7 Bcf) in that same year.

Midwest Gas expects its gas requirements to remain constant over the next five years. Its current supply arrangements, including this agreement with Salmon, are expected to meet its customers' needs for the foreseeable future. Over the past five years, Midwest Gas has been diversifying its supply portfolio by replacing some of its purchases from pipeline companies with direct producer purchases as is the case with the Shell agreement. It also purchases gas on the spot market. These measures are in keeping with Midwest Gas' objective of maintaining a balance between assured supply and competitive prices.

Shell's sale to Midwest Gas would represent approximately eight percent of Midwest Gas' annual supply requirements. Midwest Gas anticipates taking gas under the Shell/Salmon contract at a load factor of 80 percent. In providing this forecast, Midwest Gas took into account that this gas would replace volumes currently purchased from U.S. pipelines and that Midwest Gas must pay Shell/Salmon an annual

Figure 7-1

COMPARISON OF NEB'S & SHELL'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



deficiency payment if it fails to take 80 percent of the aggregate MDQ in any year. Midwest Gas stated that since this volume represented a small portion of its total supply portfolio, it did not foresee any circumstances that would cause this load factor to be reduced.

7.3.1.2 Enron Market

Enron is a gas marketing company serving markets throughout the U.S., with a strong market base in the U.S. midwest. It is a subsidiary of Enron Corp. which operates the largest natural gas transmission system in the U.S. Enron purchases natural gas from producers, aggregators, processing plants and marketing companies located in the U.S. and Canada. Its sales customers include distribution companies, industrial consumers, electric utilities, independent power plants and other marketers. Over the past five years, Enron's sales agreements have shifted from 100 percent interruptible to approximately an even mix between firm and interruptible sales. Enron uses storage facilities to support its firm obligations and to balance fluctuations between its market demand and supply availability.

Enron projected average daily sales in 1991 in the U.S. midwest of over $15\,000\,10^3\text{m}^3$ (530 MMcf) of which over $7\,500\,10^3\text{m}^3$ (265 MMcf) is expected to be sold on a firm basis. Enron provided a forecast of firm sales to this market for the years 1992 through 1995 indicating an expected doubling of daily firm sales from $15\,000\,10^3\text{m}^3$ (530 MMcf) to over $30\,550\,10^3\text{m}^3$ (1078.4 MMcf) as a result of conversions from interruptible to firm sales during those years.

Enron indicated that the purchase of Canadian gas from Shell/Salmon is part of its strategy to diversify its portfolio by securing reliable sources of long-term supply for its customers. The gas would be sold primarily in the U.S. midwest with a portion of the volumes supplying markets in California and possibly the eastern U.S. The volumes purchased under this agreement represent approximately one percent of Enron's total requirements for its markets in the U.S. midwest. Assuming the gas would be sold only to U.S. midwest markets and taking into account the contractual penalties for purchases below 100 percent and the small percentage it represents of its total supply portfolio, Enron

expects the gas to be taken at a load factor of 100 percent throughout the term of the agreement. Enron suggested that circumstances such as significant loss of nation-wide market share, major and prolonged pipeline disruptions, Canadian and U.S. regulatory changes or unanticipated, dramatic price fluctuations would have to occur before this expected load factor was affected.

7.3.2 Transportation

The proposed export volumes would be transported on the NOVA system to the Foothills system interconnect at McNeil, Alberta. Shell would use its existing firm transportation on NOVA to transport the volumes within Alberta. Copies of the NOVA transportation assignment agreements between the other six producers supplying gas to the project and Shell were filed with the application. From McNeil, Alberta, the gas would be transported on the Foothills' system to the international border at Monchy, Saskatchewan. Shell and Foothills have entered into a firm service ("FS") contract dated 15 November 1990 for the transportation of $862.6\,10^3\text{m}^3$ (30.4 MMcf) per day for a 15-year period commencing on 1 November 1991.

In the U.S., the gas would be transported by Northern Border to Ventura, Iowa. Salmon, which takes possession of the gas at the international border, has executed an FS agreement with Northern Border dated 7 April 1989 for the transportation of $850\,10^3\text{m}^3$ (30.0 MMcf) per day of gas to Ventura, Iowa for a 15-year period. Midwest Gas and Enron would receive the gas at this point. Facilities required on the Northern Border system to transport the gas were approved by the FERC on 31 October 1990.

The Midwest Gas volumes will be transported by Northern Natural to various city gate receipt points on Midwest Gas' system in Iowa, Minnesota, South Dakota and Nebraska pursuant to a firm transportation agreement between those two parties. The agreement covers the transportation of $520\,10^3\text{m}^3$ (18.4 MMcf) per day for a period of 9 years with an evergreen clause for renewal. Midwest Gas stated during the hearing that transportation for the remaining $55\,10^3\text{m}^3$ (1.9 MMcf) per day had been requested and that oral confirmation had been received from

Northern Natural. The contract would be filed with the Board as soon as it was executed.

The Enron volumes will be transported from Ventura, Iowa to Enron's markets using either the Northern Natural system or, if the gas sale and purchase agreement is amended, the NGPL system. Enron stated that it holds transportation contracts with various pipeline systems in the U.S. and that it is well positioned in other pipeline transportation queues. Enron also stated that a significant amount of the gas it sells in the midwest region is transported under its customers' own FS agreements with various pipeline companies. Enron indicated that these arrangements are sufficient to transport the gas purchased from Shell/Salmon to its markets in the midwest and, if necessary, to California.

7.3.3 Gas Sales Contracts

The proposed export volumes would first be sold at Monchy, Saskatchewan by Shell to Salmon pursuant to two separate agreements. The gas would then be resold at Ventura, Iowa pursuant to agreements between Salmon and Midwest Gas and between Salmon and Enron. Each of the two arrangements are discussed below.

7.3.3.1 Shell/Salmon/Midwest Gas Sales Contract

The natural gas destined for Midwest Gas would be sold pursuant to a gas sale and purchase agreement dated 1 March 1991 between Shell and Salmon. The contract provides for 575 10³m³ (20.3 MMcf) per day of gas to be purchased at Monchy, Saskatchewan for a period of fifteen years commencing on the later of 1 November 1991, the date on which all precedent conditions in the Salmon/Midwest contract are met, or on the in-service date of the applicable facilities. The price to be paid to Shell equals the price paid by Midwest Gas less transportation charges on Northern Border's system and Salmon's marketing fee of 1.5 percent.

Once delivered to Ventura, Iowa, the gas would be resold by Salmon to Midwest Gas under a gas sale and purchase agreement dated 31 January 1991. This contract includes the same terms and volumes as the Shell/Salmon agreement. Precedent conditions included in this contract which must be met or waived by 1 January 1992

include: obtaining all necessary Canadian and U.S. regulatory authorizations; execution of a supply contract between Salmon and Shell; and Midwest Gas entering into firm service transportation with necessary pipeline companies downstream of Ventura, Iowa.

The two-part pricing system contained in the Salmon/Midwest contract consists of a demand charge and a commodity charge.

Midwest Gas must pay a demand charge (minimum bill) each month, regardless of the quantity of gas taken, which will be equal to the greater of a) the NOVA and Foothills firm transportation charges for the month, or b) \$U.S. 308,730.00 which is \$U.S. 0.50/MMBtu (\$U.S. 0.47/GJ) times the DCQ for each day of the month. The demand charge component is not subject to renegotiation under the contract.

The commodity charge is equal to 94 percent of the FERC approved Northern Natural Zone-1 Commodity Rate for the current month minus the sum of Northern Natural's FERC approved FT-1 transportation rate; Northern Natural's fuel use and unaccounted-for gas charges; and the demand charge described in the previous paragraph. The commodity component can be renegotiated prior to the fifth and tenth contract years. Failure to agree on a new commodity component prior to 30 days before the end of those years would result in contract termination.

In addition to the above-described renegotiation opportunities, Midwest Gas can request renegotiation of the commodity component if, during four consecutive months, Northern Natural's commodity rate exceeds 120 percent of the monthly reference price which is defined as the sum of:

- a) an average spot price based on Inside FERC's current month spot market price indices for selected midwestern pipelines;
- b) Northern Natural's current Field to Market Zone interruptible transportation rate based on 200 miles;
- c) Northern Natural's IT-1 FERC gas Tariff Market Zone rate; and

- d) an allowance of 3.5 percent for fuel use and unaccounted-for gas.

This reference price is used as a comparison to ensure a price which would not exceed 20 percent over the current spot prices in Midwest Gas' market area. Failure to reach agreement during this renegotiation process will result in binding arbitration.

Under the terms of the contract, Midwest Gas must take 80 percent of the aggregate of the MDQ in a contract year or pay 20 percent of the commodity charge in effect during the last month of that year for each MMBtu that the actual take was under 80 percent. Midwest Gas can make-up volumes not taken in the previous year in the next year at the then current price which would then be deducted from the deficiency payment previously made. Salmon, on the other hand, is responsible for an under-delivery penalty payment to cover any incremental replacement costs for gas it fails to deliver. Salmon must also adjust demand charges during periods of under-delivery.

The estimated price that would have been in effect under the terms of this contract at the Alberta border as of 1 March 1991 was \$ Cdn. 1.13/GJ (\$ Cdn. 1.21/MMBtu).

7.3.3.2 Shell/Salmon/Enron Gas Sales Contract

The natural gas destined for Enron would be sold pursuant to a gas sale and purchase agreement dated 31 March 1991 between Shell and Salmon. The contract provides for 275 10³m³ (9.7 MMcf) per day of gas to be purchased at Monchy, Saskatchewan for a period of ten years commencing on the later of 1 November 1991, or the date which all precedent conditions in the Salmon/Enron contract are met, or on the in-service date of the applicable facilities. The price to be paid to Shell equals the price paid by Enron less transportation charges on Northern Border's system and Salmon's marketing fee of 1.5 percent.

The gas would be resold at Ventura, Iowa pursuant to a gas sales and purchase contract between Salmon and Enron dated 31 March 1991. This contract includes the same terms and conditions outlined in the Shell/Salmon contract related to this sale. The Salmon/Enron contract

includes several conditions precedent which must be met or waived by 1 January 1992. Included are a) Shell and Salmon obtaining necessary transportation arrangements to Ventura, Iowa; b) Enron or its designee obtaining necessary transportation arrangements downstream of Ventura, Iowa; and c) all necessary U.S. regulatory approvals for import and transport to Ventura, Iowa.

The price to be paid by Enron is based on a two-part pricing structure comprised of the sum of a demand component which equals Salmon's costs incurred in reserving firm transportation on Northern Border to a maximum of \$U.S. 0.50/MMBtu (\$U.S. 0.47/GJ) and a two-tier commodity price component based on Enron's firm California market and the midwestern spot market.

The Tier I commodity charge is equal to the California reference price less interruptible transportation for backhaul service on Northern Natural from Ventura, Iowa to either the El Paso Natural Gas Co. or Transwestern Pipeline Co. interconnects, and the previously described demand charge. A ceiling of \$U.S. 0.18/MMBtu (\$U.S. 0.17/GJ) in the summer and \$U.S. 0.28/MMBtu (\$U.S. 0.26/GJ) in the winter has been set for this backhaul rate. The California reference price is defined as the actual weighted average sale price of Enron's firm sales in its California market under contracts with terms of at least one year. These contracts must contain non-performance penalties and have a fixed sales price for at least three months or prices related to a gas-based index.

The Tier II commodity charge is equal to a monthly reference price minus Enron's marketing fee of \$U.S. 0.05/MMBtu (\$U.S. 0.05/GJ). The monthly reference price is defined as the sum of the average spot market prices of specified midwestern pipelines as published by Inside FERC plus Northern Natural's Field to Market Zone interruptible rate based on 200 miles and a 1.25 percent allowance for fuel use and unaccounted-for gas.

Under the contract terms, Enron must purchase 100 percent of the monthly contract quantity or pay 20 percent of the monthly reference price for each MMBtu not taken. Shell must also pay the same penalty for each MMBtu under the monthly

contract quantity which it fails to deliver and must reduce the monthly demand charge accordingly. At least 65 percent of the annual volume of gas taken must be at the Tier I price or Enron must make adjustment payments between the Tier I and Tier II prices to make-up the 65 percent at the end of each year.

Price renegotiation is available prior to the end of the first five years of the contract in order to determine the pricing provisions which will apply for the next five years. Either party can elect to terminate the contract after the first five years if an agreement is not reached during this renegotiation six months prior to the end of the first five years. Provision is also made for either party to request renegotiation of the average spot price contained in the Tier II component if the determinants are no longer available or no longer reflect the current market conditions. Binding arbitration is available if this renegotiation process fails.

The estimated price that would have been in effect under the terms of this contract at the Alberta border as of 1 March 1991 was \$ Cdn. 1.03/GJ (\$ Cdn. 1.10/MMBtu).

7.3.4 Regulatory Status

The proposed export volumes would be removed from the province of Alberta pursuant to Shell's ERCB removal permit GR89-47A issued on 13 December 1990 which provides for the removal of gas until 30 June 2010. Shell applied to the AERCB on 25 June 1991 for an amendment to this permit to include the proposed sales to Midwest Gas and Enron.

Application to the DOE/FE was to be made by mid-July, 1991 for import authorization for terms of 15 years for Midwest Gas and 10 years for Enron.

Northern Border received authorization for its required facilities from the FERC on 31 October 1990 under docket number CP89-576-001. The facilities are expected to be in service by 1 November 1991.

7.4 Views of the Board

The Board's estimate of reserves exceeds Shell's total requirements, and the Board's projection of

productive capacity suggests that Shell will be able to meet its requirements throughout the term of the proposed licences with a possible minor deficiency for only one year. The Board agrees that Shell could remedy any shortfall in productive capacity from its other properties or by purchasing additional gas reserves. The Board is therefore satisfied with the adequacy of Shell's supply relative to its requirements.

The Board is satisfied that the proposed sales to Salmon for resale to Midwest Gas and to Enron represent a stable long-term market for Canadian gas. Given that the volumes and the competitive pricing provisions associated with both sales do not represent a significant portion of either end-users' supply portfolio, the Board is of the view that any reduction in these markets would not impact solely on these Canadian sales.

The Board notes that transportation arrangements within Canada have been completed and all transportation agreements have been finalized. In the U.S., Salmon has contracted for firm capacity on Northern Border for the proposed volumes. Both Midwest Gas and Enron were able to satisfactorily demonstrate that, for the major portion of the proposed volumes, transportation in the form of executed FS agreements had been provided.

The Board's review of the export sales arrangements, i.e. Shell/Salmon/Midwest Gas and Shell/Salmon/Enron, has indicated that the contracts would be durable over time and that gas will likely be taken at high load factors over the term of the contracts. The Board is also satisfied that the inclusion of demand charge components in the contracts assures adequate recovery of Canadian transportation costs.

Although the Shell/Salmon agreements cannot be termed arm's-length, the Board looked to the resale or third party agreements and, given the flow-through nature of the contractual terms and conditions, is satisfied with the arm's-length nature of these agreements.

The Board notes that the AERCB amended removal permit and DOE/FE import authorization remain outstanding, but is of the view that these are not likely to be an impediment to Shell's proposed export.

7.5 Decision

The Board has decided to issue two gas export licences to Shell, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licences, including a condition in each that the term of the licences shall commence upon Governor in Council approval and shall end on 1 November 1994, unless exports have commenced under the licences on or before 1 November 1994, in which case the terms would end ten or fifteen years following the respective commencement date of the licences.

Chapter 8

Disposition

The foregoing chapters constitute our Decision and Reasons for Decision, Volume II in respect of the export applications heard by the Board in the GH-3-91 proceedings.



R. Illing
Presiding Member



W.G. Stewart
Member



C. Bélanger
Member

Calgary, Canada
March 1992

Appendix I

Terms and Conditions of the Licences to be Issued

Terms and Conditions of the Licence to be Issued to Amoco Canada Petroleum Company Ltd.

1. The term of this Licence shall commence on 1 November 1992 or the date of first deliveries, whichever is the later, and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end ten years following commencement of the term of this Licence.
2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:
 - (a) 424 900 cubic metres in any one day;
 - (b) 155 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or
 - (c) 1 551 000 000 cubic metres during the term of this Licence.
3. (a) As a tolerance, the amount that Amoco Canada may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that Amoco Canada may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.
4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence to be Issued to Canadian Occidental Petroleum Ltd.

1. The term of this Licence shall commence on 1 November 1992 or the date of first deliveries, whichever is the later, and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end ten years following commencement of the term of this Licence.
2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:
 - (a) 212 500 cubic metres in any one day;
 - (b) 77 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or
 - (c) 775 500 000 cubic metres during the term of this Licence.
3. (a) As a tolerance, the amount that CanadianOxy may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that CanadianOxy may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.
4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence to be Issued to ProGas Limited for Sale to Lockport Energy

1. The term of this Licence shall commence on 1 November 1992 or the date of first deliveries, whichever is the later and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end 15 years following commencement of the term of this Licence.
2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:
 - (a) 339 934 cubic metres in any one day;
 - (b) 124 075 760 cubic metres in any consecutive twelve-month period ending on 31 October; or
 - (c) 1 861 136 400 cubic metres during the term of this Licence.
3. (a) As a tolerance, the amount that ProGas may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that ProGas may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.
4. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

Terms and Conditions of the Amending Order to Gas Export Licence GL-129 to be Issued to ProGas Limited

1. This Order shall become effective on 1 November 1992 or the date that Governor in Council approval is received for the new licence to be issued to ProGas Limited for its sale to Lockport Energy Associates, L.P. whichever is the later.

2. Licence GL-129 will be amended by revoking Condition 2 and replacing it with the following:

- "2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:
- (a) 2 521 116 cubic metres in any one day;
 - (b) 920 224 300 cubic metres in any consecutive twelve-month period ending on 31 October; or
 - (c) 13 804 160 000 cubic metres during the term of this licence."

Terms and Conditions of the Licence to be Issued to ProGas Limited for Sale to NSPW

1. The term of this Licence shall commence on 1 November 1992 or the date of first deliveries, whichever is the later and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end ten years following the commencement of the term of this Licence.
2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:
 - (a) 212 458 cubic metres in any one day;
 - (b) 77 547 170 cubic metres in any consecutive twelve-month period ending on 31 October; or
 - (c) 775 471 700 cubic metres during the term of this Licence.
3. (a) As a tolerance, the amount that ProGas may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that ProGas may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence to be Issued to Shell Canada Limited for Sale to Enron

1. The term of this Licence shall commence upon Governor in Council approval and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end ten years following commencement of the term of this Licence.
2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:
 - (a) 278 000 cubic metres in any one day;
 - (b) 102 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or
 - (c) 1 014 000 000 cubic metres during the term of this Licence.
3. (a) As a tolerance, the amount that Shell may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that Shell may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.
4. Gas exported under the authority of this Licence shall be delivered to the point of export near Monchy, Saskatchewan.

Terms and Conditions of the Licence to be Issued to Shell Canada Limited for Sale to Midwest Gas

1. The term of this Licence shall commence upon Governor in Council approval and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end fifteen years following commencement of the term of this Licence.
2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:
 - (a) 580 000 cubic metres in any one day;
 - (b) 212 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or
 - (c) 3 181 000 000 cubic metres during the term of this Licence.
3. (a) As a tolerance, the amount that Shell may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that Shell may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.
4. Gas exported under the authority of this Licence shall be delivered to the point of export near Monchy, Saskatchewan.

